State of California

Department of Water Resources

Supplemental Determination of Revenue Requirements

For the Period

January 1, 2004 Through December 31, 2004

Submitted To
The California Public Utilities Commission
Pursuant To
Sections 80110 and 80134 of the California Water Code

April 19, 2004

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A. THE SUPPLEMENTAL DETERMINATION

In this Supplemental Determination of Revenue Requirements for the period January 1, 2004 through and including December 31, 2004, (this "Supplemental Determination"), the California Department of Water Resources ("the Department" or "DWR") is decreasing its 2004 revenue requirements as described herein. The Department has identified that, assuming current customer rates remain in place throughout 2004, it will have $245 million more in power charge revenues than are needed to meet its required reserve and operational requirements. In reaching this Supplemental Determination, the Department has considered the reasonableness of making a reduction to its revenue requirements, including consideration of comments provided by California investor owned utilities ("IOUs" or "Utilities") on April 1, 2004, pursuant to regulations promulgated under the California Administrative Procedure Act ("APA"). Contemporaneous with reaching this Supplemental Determination, the Department is submitting this Supplemental Determination to the California Public Utilities Commission ("CPUC" or "Commission") for the purpose of establishing charges upon electric retail customers in the service territories of the IOUs pursuant to the Rate Agreement between the Commission and the Department (the "Rate Agreement"). Capitalized terms used and not otherwise defined herein have the meanings given to such terms in the Rate Agreement, the Indenture under which the Department's Power Supply Revenue Bonds were issued (the "Bond Indenture") or the September 18, 2003 Determination described below.

GENERAL

On September 18, 2003, the Department issued its Determination of Revenue Requirements for the period of January 1, 2004 through and including December 31, 2004 (the "September 18, 2003 Determination") and submitted it to the Commission. On January 8, 2004, the Commission adopted Decision 04-01-028 "Order Implementing an Interim Allocation of the 2004 Revenue Requirement Determination of the California Department of Water Resources and Truing Up The 2001-2002 Revenue Requirement Determination of the California Department of Water Resources." Decision 04-01-028 allocated the Department's 2004 revenue requirement for its power purchase program among retail customers in the service territories of the three IOUs – namely Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE") and San Diego Gas & Electric ("SDG&E") – on an interim basis.

The Department has reviewed certain matters relating to its 2004 revenue requirement, including, but not limited to, operating results of the Electric Power Fund (the "Fund") as of December 31, 2003; contract dispatch and cost modeling; developments in natural gas markets; and Commission decisions issued subsequent to the September 18, 2003 Determination. The Department has concluded that a supplemental revenue requirement determination addressing the following issues would be useful to the Commission in adjusting the allocation of revenue requirements established by Decision 04-01-028, and would benefit retail rate payers in the IOUs' service territories:

- Electric Power Fund Account Balances;

- Extraordinary Costs;
- Bundled Customer Load Forecasts;
- El Paso Energy Settlement Agreement;
- Direct Access Load Forecasts;
- Contract Dispatch and Cost Modeling;
- Natural Gas Price Forecasts and Related Assumptions;
- IOU Planned Outage Schedules; and
- Hydroelectric Conditions in California and the Pacific Northwest.

RELATIONSHIP TO OTHER DETERMINATIONS OF THE DEPARTMENT'S REVENUE REQUIREMENTS

This Supplemental Determination addresses only those changes under the subjects noted above. All other previous assumptions underlying the September 18, 2003 Determination remain unchanged for the purposes of this Supplemental Determination. The Department intends to determine and submit to the Commission its revenue requirements for 2005 later this year.

HIGHLIGHTS OF THE SUPPLEMENTAL DETERMINATION OF REVENUE REQUIREMENTS

On the basis of the materials presented and referred to by this Supplemental Determination, the Department hereby determines its cash-basis Retail Revenue Requirement[1] for the period of January 1, 2004 through December 31, 2004, to be $5.164 billion, to consist of $4.272 billion from power charge revenues and $892 million in bond charge revenues. Bond Related Costs have not significantly changed in comparison to the September 18, 2003 Determination and, as a result, will not be discussed in this Supplemental Determination.

A primary consideration motivating this Supplemental Determination is the higher-than-projected aggregate ending account balance in the Department's Power Charge Accounts as of December 31, 2003. The higher-than–projected aggregate account balance resulted from the net effects of increased Departmental revenue receipts and increased operational costs during the last half of calendar year 2003. The September 18, 2003 Determination included actual information through June 2003 and projected July through December 2003.

Several factors have contributed to the collection of higher-than-projected revenues during the 2003 Revenue Requirement Period including the following: (1) Power Charge revenues, which exceeded projections by approximately $244 million due primarily to higher-than-projected energy sales by the Department to bundled customers, higher-than-

[1] Although the Department will use herein the term "Retail Revenue Requirement" which, as defined by the Rate Agreement, means the amounts to be generated from Power Charges on Retail End Use Customers (i.e., bundled customers of the IOUs), such revenue requirement may also be satisfied by Direct Access Power Charge Revenues (as that term is defined in the Bond Indenture).

expected Power Charge remittances by PG&E (approximately $56 million through December 31, 2003) and a delay in shifting prioritization of the Direct Access Cost Responsibility Surcharge ("CRS") Competitive Transition Charge component relative to the Direct Access CRS Power Charge component; (2) the Department received FERC-ordered settlement monies totaling approximately $15.5 million in 2003 (as well as $6.1 million in January 2004); (3) the Department received approximately $89 million more than projected from off-system sales transactions due to increased sales volumes and higher wholesale prices; and (4) the Department received $3 million more than projected in interest earnings on fund balances. In combination, these factors resulted in the Department collecting $352 million more than the amount of revenues that had been forecast for the 2003 Revenue Requirement Period. These revenue increases are discussed in greater detail in Section E of this Supplemental Determination.

Offsetting these revenue increases, the Department incurred $78 million more than the amount of operating expenses that had been forecast for the 2003 Revenue Requirement Period. The Department incurred $74 million more than projected in power costs due to (a) the Department's procured energy volume exceeding projections by more than 954 GWh, and (b) higher-than-expected gas prices. The remaining $4 million in higher-than-projected costs resulted from actual administrative and general expenses exceeding forecasts. These cost increases are also discussed in Section E of this Supplemental Determination.

The net effect of these factors was an aggregate beginning balance, as of January 1, 2004, in the Power Charge Accounts that exceeded the projected amount by $275 million.

In addition to these historical factors affecting this Supplemental Determination, the Department has identified necessary revisions to forecasting assumptions in the following areas: bundled customer load, IOU planned outage schedules, fuel prices, contract dispatch and cost modeling, and annual hydroelectric generation and dispatch. The combined impact of these revised assumptions is a net increase to the Department's forecasted 2004 annual power costs of $161 million when compared to the power cost forecasts for 2004 included in the September 18, 2003 Determination. This increase is partially offset by a reduction in Extraordinary Costs related to fuel hedging of $34 million, resulting in a Total Power Cost increase of $127 million. Relevant changes to the Department's assumptions underlying this Supplemental Determination are discussed in Section E.

SUMMARY OF RETAIL REVENUE REQUIREMENTS (Power Side)

Description	2004 Supplemental	2004	Difference
	$ millions	$ millions	$ millions
Sources of Funds			
Revenue from Customers	4,272	4,517	(245)
Off System Sales and Extraordinary	324	135	189
Interest	32	31	1
Reduction Operating Reserve Balances	327	145	182
Total Sources to Service Costs	4,956	4,828	127
Uses of Funds			
Total Power Costs	4,956	4,828	127
	-	-	-
Total Uses of Funds	4,956	4,828	127

Table A-1 shows a summary of the Department's revenue requirements and the account balances associated with its projected Department Costs ("Power Charge Accounts") for the 2004 Revenue Requirement Period. These figures are compared to those reflected in the September 18, 2003 Determination. Assumptions underlying these revenue requirements and account balances are discussed in Section E.

Table A-1
Summary of the Department's 2004 Retail Revenue Requirement and Power Charge Account Balances[1] ($ millions)

Line	Description	2004 Supplemental [2]	2004 [3]	Difference
1	*Beginning Balance in Power Charge Accounts*			
2	Operating Account	1,031	756	275
3	Priority Contract Amount	-	-	-
4	Operating Reserve Account	630	630	-
5	**Total Beginning Balance in Power Charge Accounts**	**1,660**	**1,386**	**275**
6	*Power Charge Accounts Operating Revenues*			
7	Power Charge Revenues from Bundled Customers[4]	4,272	4,517	(245)
8	Extraordinary Receipts from Utilities	46	-	46
9	Contract Settlements	6		6
10	Other Power Sales	273	135	137
11	Interest Earnings on Fund Balances	32	31	1
12	**Total Power Charge Accounts Operating Revenues**	**4,628**	**4,683**	**(55)**
13	*Power Charge Accounts Operating Expenses*			
14	Administrative and General Expenses	59	59	0
15	Total Power Costs	4,860	4,698	161
16	Extraordinary Costs	37	71	(34)
17	**Total Power Charge Accounts Operating Expenses**	**4,956**	**4,828**	**127**
18	Net Operating Revenues	(327)	(145)	(182)
19	Net Transfers from/(to) Bond Charge Accounts & Adjustments	7	-	7
20	Total Net Revenues	(321)	(145)	(176)
21	**Ending Aggregate Balance in Power Charge Accounts**	**1,340**	**1,240**	**99**

2004 Target Minimum Power Charge Account Balances	Target (Millions of Dollars)		
Operating Account: this minimum balance is targeted to cover intra-month volatility as measured by the maximum difference in revenues and expenses in a calendar month.	296	285	11
Operating Reserve Account: covers deficiencies in the Operating Account. It is sized as the greater of (i) the maximum seven-month difference between operating revenues and expenses as calculated under a stress scenario and (ii) 12% of the Department's projected annual operating expenses for the current or immediately preceding Revenue Requirement Period.	595	579	16
Total Operating Reserves:	891	864	27

[1] Numbers may not add due to rounding.
[2] As proposed herein.
[3] As reflected in the Department's 2004 Determination.
[4] CRS Revenues are included in this amount.

B. BACKGROUND

The September 18, 2003 Determination provided background information related to Section 80110 of the Water Code and a history of the Department's revenue requirement determinations. The background information included a review of the adoption of the Rate Agreement between the Commission and the Department and discussed the purpose of, and actions required under, the Rate Agreement.

For purposes of this Supplemental Determination, the background information contained in the September 18, 2003 Determination is incorporated by reference and will not be repeated herein. The September 18, 2003 Determination and the administrative record of materials on which it was based are part of the administrative record of materials underlying this Supplemental Determination.

On July 18, 2003, the Department published its Proposed Determination of Revenue Requirements for the period January 1, 2004 through December 31, 2004 ("Proposed Determination"). In accordance with the Department's regulations, opportunity was provided for public comment on the Proposed Determination. Comments were received by the Department from SCE, SDG&E, and PG&E on August 14, 2003. These comments were reviewed, and where appropriate, incorporated into the Department's Final Determination issued on September 18, 2003[2]. On September 18, 2003 the Department submitted the Determination to the Commission.

Subsequent to the issuance of the September 18, 2003 Determination, there have been significant developments that impact the Department's revenue requirements for 2004. The Department made a preliminary analysis of potential changes to its Retail Revenue Requirement and now believes it is appropriate to revise the September 18, 2003 Determination with a Supplemental Determination addressing and incorporating significant changes that arose subsequent to the September 18, 2003 Determination.

Factors relative to this Supplemental Determination are identified and discussed in Section E of this Supplemental Determination.

[2] For further information pertaining to the process followed, refer to the September 18, 2003 Determination, Section F entitled "Just and Reasonable Determination".

C. RECONCILIATION

This section provides a reconciliation of the significant changes with respect to the Retail Revenue Requirement in addition to projected Department Costs, Power Charge Revenues and Direct Access Power Charge Revenues.

POWER CHARGE ACCOUNTS OPERATING EXPENSES

Total Department Costs (specified below) are projected to increase by $ 127 million.

Administrative and General Costs
During the 2004 Revenue Requirement Period, Departmental administrative and general costs are not expected to vary from forecasts submitted in the September 18, 2003 Determination. The original estimate of $59 million remains unchanged, assuming $55 million for the Department's appropriated budget plus $4 million for consulting services for development and monitoring of the revenue requirements and financial advisory and related consulting services for managing the $11 billion debt portfolio and related swaps and reserves. Details related to the Department's appropriation within the 2003-2004 State Budget are discussed within the September 18, 2003 Determination and will not be repeated herein.

Total Power Costs
The September 18, 2003 Determination projected contract purchases of 58,798 GWh, which has been revised to 62,228 GWh, an increase of 3,430 GWh. The key factors contributing to the increase in projected power sales are described in Section E.

Due, in part, to the increase in power sales, the total cost of purchased power is expected to increase by $161 million. This increase is attributed primarily to the factors discussed in Section E, including increased fuel expenses and certain changes to modeled power contract assumptions.

Extraordinary Costs
During the 2004 Revenue Requirement Period, Departmental extraordinary costs (gas contract collateral deposits) are not expected to differ from forecasts included in the September 18, 2003 Determination. The estimate of $71 million has been revised to $37 million based on the required deposit of $71 million, as described earlier, less $34 million that remained on deposit in the external hedging account as of December 31, 2003. The fuel hedging estimate is based, as before, on using gas futures contracts to hedge the June through December 2004 gas requirements. The final 2004 amount will be based on gas hedges proposed by the investor-owned utilities who are managing the Department's contracts. These hedging arrangements are proposed to reduce exposure to a potentially volatile gas fuel supply market with potentially higher gas costs which may be incurred without these gas futures contracts.

POWER CHARGE ACCOUNTS OPERATING REVENUES

Total revenue for deposit in Power Charge Accounts (specified below) is projected to decrease by a net $55 million.

Power Charge Revenues from Bundled Customers and Direct Access Customers
Power Charge Revenues needed to be derived from bundled customers and direct access customers are projected to be $245 million less than previously projected. The reduction in needed revenues primarily results from higher-than-projected aggregate ending Power Charge Account balances as of December 31, 2003. The $275 million difference between actual and forecasted balances, in concert with the consideration of other forecasted variables, has allowed the Department to reduce its needed power charge revenues by the aforementioned amount.

Extraordinary Receipts
During the 2004 Revenue Requirement Period, the Department projects receipt of approximately $46 million in extraordinary revenues. This total results from the net effect of reimbursements from the Department due to PG&E and SCE as a result of higher-than-projected Power Charge remittances received by the Department through December 31, 2003 and payments due to the Department from PG&E.

For purposes of this Supplemental Determination, The Department has assumed that during the first half of 2004, the Department expects to return to ratepayers through the IOUs: (1) $56 million in excessive Power Charge remittances from PG&E in 2003 and (2) $23 million remaining to be returned to customers in the SCE service area related to the $1 billion 2003 revenue requirement reduction.

In addition, extraordinary receipts include the following payments from PG&E: (1) an accrued interest payment for historical "WAPA" under-remittances of $38 million (received in February 2004); (2) $84 million in "pre-petition" bankruptcy amounts owed to the Department by PG&E (projected for purposes of this determination to be received on April 14, 2004), and (3) an interest payment of $2 million on the "pre-petition" amounts owed to the Department.

On April 1, 2004, PG&E filed a petition with the California Supreme Court asking the Court grant a Writ of Review of CPUC Decisions relating to the "WAPA" interest payment. PG&E has asked the court to annul the CPUC Decisions insofar as they require PG&E to remit an amount more than $13.3 million. It is the Department's belief that, should the Supreme Court annul the CPUC Decisions, the CPUC would then need to address any such order through ratemaking mechanisms so as to repay PG&E shareholders. For purposes of this Supplemental Determination the Department does not anticipate returning any funds received for the "WAPA" interest payment to PG&E.[3]

As previously noted, the cumulative effect of these transactions is a net inflow to the Department of $46 million during the 2004 Revenue Requirement Period.

[3] See Section G for the PG&E Petition For Writ Of Review filed with the California Supreme Court.

Contract Settlements
This Supplemental Determination takes into account the receipt of $6.1 million (received in January 2004) resulting from a FERC-ordered settlement with Portland General Electric Company in September 2003. With respect to this settlement, FERC's approval was granted in its Order Approving Offer of Settlement and Granting Motion to Transfer, related to docket numbers EL02-114-000 and EL02-115-001, as issued on September 26, 2003. This Order references Exhibit A of the Offer of Settlement as to Portland General Electric Company, agreed to on September 26, 2003, in which the sum of $6.1 million was allocated for payment to the Department's Electric Power Fund.

Other Power Sales
Revenue from Other Power Sales is projected to be $137 million more than previously projected, as described in Section E.

Interest Earnings on Fund Balances
Revenue from Interest Earnings is projected to be $1 million more than previously projected, as a result of increased account balances, as described below.

Power Charge Account Balances
The Department has determined that the Minimum Operating Expense Available Balance ("MOEAB") is determined to be an amount $11 million greater than previously determined. The Bond Indenture requires this amount to be "the maximum amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any one calendar month during that Revenue Requirement Period . . . based on such assumptions as the Department deems to be appropriate after consultation with the Commission and . . . [taking] into account a range of possible future outcomes."

The Department has determined that the Operating Reserve Account Requirement ("ORAR") is determined to be an amount $16 million greater than previously determined. This account is available to cover deficiencies in the Operating Account and is now required to be "the greater of (i) the largest aggregate amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any consecutive seven (7) calendar months commencing in the Revenue Requirement Period, and (ii) 12 percent of the Department's projected annual Operating Expenses for the Revenue Requirement Period but not less than 12 percent of the Department's Operating Expenses for the most recent twelve (12) calendar month period." For the 2004 Revenue Requirement Period, 12 percent of Operating Expenses for the period of January through December 2003 is the greater amount and is used to calculate the $595 million requirement.

Power Charge Revenues from Bundled Customers and Direct Access Customers
Power Charge Revenues needed to be derived from bundled customers and direct access customers are projected to be $245 million less than previously projected. The reduction in needed revenues primarily results from higher-than-projected aggregate ending Power Charge Account balances as of December 31, 2003. The $275 million difference between actual and forecasted balances, in concert with the consideration of other forecasted

variables noted above, has allowed the Department to reduce its needed Power Charge Revenues by the aforementioned amount.

D. THE DEPARTMENT'S SUPPLEMENTAL DETERMINATION OF REVENUE REQUIREMENTS FOR THE PERIOD OF JANUARY 1, 2004 THROUGH DECEMBER 31, 2004

SUPPLEMENTAL REVENUE REQUIREMENT DETERMINATION

For the 2004 Revenue Requirement Period, which commenced January 1, 2004 and ends December 31, 2004, the Department's revenue requirements consist of Department Costs and Power Charge revenues, and Bond Related Costs and Bond Charge Revenues. With respect to this Supplemental Determination, there are no material changes related to the Department's Bond Related Costs or Bond Charge Revenues. Only Department Costs and Power Charge revenues will be discussed herein.

Department Costs include:

(1) Costs associated with power supply to be delivered under the Department's existing Priority Long-Term Power Contracts ("PLTPCs");

(2) Operating reserves as determined by the Department (see Table A-1);

(3) Extraordinary costs (gas contract collateral deposits); and

(4) Administrative and general expenses.

Revenues available to pay Department Costs include:

(1) Revenues from other power sales;

(2) Interest earnings; and

(3) Power Charge revenues (including both Power Charge Revenues and Direct Access Power Charge Revenues, as those terms are defined in the Bond Indenture).

This Supplemental Determination is made on the premise that the Department will not procure the residual net short at any time during 2004.

During 2004, the Department projects that it will incur the following costs: (a) $4.860 billion in costs for long-term power contract purchases to cover the portion of the net short requirement of the Customers associated with long-term energy supply contracts entered into by the Department prior to January 1, 2003 on behalf of its Retail End Use Customers; (b) $59 million in administrative and general expenses; (c) $37 million in extraordinary costs; and (d) no net transfers to Bond Charge accounts. This results in a total of $4.956 billion in Department Costs.

Funds to meet these costs are projected to be provided from (a) $273 million from the Department's share of excess power sales; (b) $32 million of interest earned on Power Charge Account balances; (c) $46 million of extraordinary receipts from PG&E; (d) $6 million of receipts due to FERC-related settlements; and (e) $4.272 billion of Power Charge Revenues and Power Charge Revenues generated from a Direct Access CRS. These revenues total $4.628 billion. The remaining requirement of $321 million is met through a $321 million reduction in Power Charge Account balances that, in part, results from an aggregate ending balance (as of December 31, 2003) in the Power Charge Accounts that was $275 million higher than projected. In addition to these factors the Departments Financial Model Operating Account was increased by $7 million due to reconciliation with actual Department cash balances. The causes of this difference between actual and projected ending aggregate balances in the Power Charge Accounts are described in detail in Section E.

Table D-1 provides a quarterly review of costs and revenues associated with the Power Purchase Program.

Table D-1
Power Purchase Program, Revenue Requirement Base Case: Retail Customer Power Charge Cash Requirement ($ millions)

Line	Description	Amounts for Revenue Requirement Period				
		2004 - Q1	2004 - Q2	2004 - Q3	2004 - Q4	Total
1	*Power Charge Accounts Expenses*					
2	Power Costs	1,133	1,052	1,413	1,262	4,860
3	Administrative and General Expenses	15	15	15	15	59
4	Extraordinary Payments	37	-	-	-	37
5	Net Changes to Power Charge Account Balances	(74)	11	(238)	(20)	(321)
6	**Total Power Charge Accounts Expenses**	**1,111**	**1,077**	**1,190**	**1,257**	**4,635**
7	*Power Charge Accounts Revenues*					
8	Extraordinary Receipts from Utilities	(41)	87			46
9	Contract Settlements	6				6
10	Other Power Sales Revenues	75	50	68	79	273
11	Interest Earnings on Power Charge Account Balance	12	-	20	-	32
12	Operating Account Balance Adjustment	7				7
13	Total Power Charge Revenue Requirement	1,051	940	1,102	1,178	4,272
14	**Total Power Charge Accounts Revenues**	**1,111**	**1,077**	**1,190**	**1,257**	**4,635**

E. ASSUMPTIONS GOVERNING THE DEPARTMENT'S SUPPLEMENTAL REVENUE REQUIREMENTS FOR THE 2004 REVENUE REQUIREMENT PERIOD

Revenue requirements for the period January 1, 2004, through and including December 31, 2004, are based on assumptions regarding sales, power supply, natural gas prices, off-system sales, demand side management and conservation, and administrative and general expenses. The Department re-examined the assumptions affecting its costs and revenues and determined that many assumptions are unchanged from the September 18, 2003 Determination. Other assumptions have changed based upon information made available subsequent to September 18, 2003, and the revised assumptions are identified and explained in detail below.

This Supplemental Determination addresses changes in the following specific areas:

- Electric Power Fund Account Balances;
- Extraordinary Costs;
- Bundled Customer Load Forecasts;
- El Paso Energy Settlement Agreement;
- Direct Access Load Forecasts;
- Contract Dispatch and Cost Modeling;
- Natural Gas Price Forecasts and Related Assumptions;
- IOU Planned Outage Schedules; and
- Hydroelectric Conditions in California and the Pacific Northwest.

ELECTRIC POWER FUND ACCOUNT BALANCES

A primary consideration motivating this Supplemental Determination is the higher-than-projected aggregate ending account balance in the Department's Power Charge Accounts as of December 31, 2003. The higher-than–projected aggregate account balance resulted from the net affects of increased Departmental revenue receipts and increased operational costs during the last half of calendar year 2003.

Several factors have contributed to the collection of higher-than-projected revenues during the 2003 Revenue Requirement Period including: (1) Power Charge revenues, which exceeded projections by approximately $244 million due primarily to higher-than-projected energy sales by the Department to bundled customers, higher-than-expected Power Charge remittances by PG&E (approximately $56 million through December 31, 2003) and a delay in shifting prioritization of the Competitive Transition Charge component of the Direct Access CRS relative to the Power Charge component of the Direct Access CRS; (2) the Department received FERC settlement monies totaling approximately $15.5 million in 2003 (as well as $6.1 million in January 2004); (3) the Department received approximately

$89 million more than projected from off-system sales transactions due to increased sales volumes and higher wholesale prices; and (4) the Department received $3 million more than projected in interest earnings on fund balances. In combination, these factors resulted in the Department collecting $352 million more than the amount of revenues that had been forecast for the 2003 Revenue Requirement Period.

Higher-than-projected dispatches of power under the Priority Long Term Power Contracts also have a direct impact on the amount of Power Charge revenues received by the Department. During the 2003 Revenue Requirement Period, actual IOU dispatches of Departmental power contracts exceeded related forecasts by nearly 954 GWh. In aggregate, PG&E's and SCE's scheduled dispatches of Department power contracts surpassed forecasted totals by more than 1,672 GWh. This excess was offset by SDG&E dispatching almost 722 GWh less than forecast. A primary causal example underpinning PG&E's higher-than-expected dispatch of Department power contracts was a prolonged refueling outage at Unit 2 of its Diablo Canyon generating facility. The lengthy reduction in this PG&E-owned generating resource resulted in a net short that exceeded the related forecast by 420 GWh. Other resource-specific examples affecting the positive variance between actual and forecasted Department-procured energy volumes are discussed below.

With respect to the Department's receipt of funds related to FERC-approved settlements, the FERC issued on July 23, 2003 an Order Approving Contested Settlement, related to docket numbers EL02-113-000 and EL02-113-002. This Order approved the contested settlement between El Paso Electric Company, the California Attorney General, the California Electricity Oversight Board and the Commission in which $15.5 million in refunds was directed to be paid by El Paso Electric Company to the Department. Following this Order, the sum of $15.5 million was received by the Department and deposited, pursuant to the Order, in the Department's Electric Power Fund in October 2003.

A second receipt of $6.1 million was recorded in the Department's Power Charge Account in January 2004, resulting from a FERC-approved settlement with Portland General Electric Company. This settlement was approved in FERC's Order Approving Offer of Settlement and Granting Motion to Transfer, related to docket numbers EL02-114-000 and EL02-115-001, as issued on September 26, 2003. This Order references Exhibit A of the Offer of Settlement As to Portland General Electric Company, agreed to on September 26, 2003, in which the sum of $6.1 million was allocated for payment to the Department's Electric Power Fund. Though the settlement receipt from Portland General Electric did not contribute to the Department's higher-than-projected, aggregate ending Power Charge Account balances in 2003, January's (2004) settlement remittance is reflected in this Supplemental Determination for the 2004 Revenue Requirement Period.

Due to the aforementioned deviation between actual and forecasted IOU dispatches of Priority Long Term Power Contracts, as well as other contributing factors described in this section, the Department incurred more than $74 million in unexpected power costs during the 2003 Revenue Requirement Period.

The net effect of these observations was an aggregate beginning balance, as of January 1, 2004, in the Power Charge Accounts that exceeded expectations by $275 million.

In addition, the Department is projecting the receipt of approximately $46 million in extraordinary revenues during the 2004 Revenue Requirement Period. As previously noted, this total results from the net effect of reimbursements due to PG&E and SCE as a result of higher-than-projected Power Charge remittances received by the Department through December 31, 2003 and payments due to the Department, which result from accrued interest on PG&E's historical "WAPA" under-remittances as well as "pre-petition" amounts owed to the Department by PG&E.

Through December 31, 2003, the Department received nearly $56 million in excessive Power Charge remittances from PG&E. The $56 million overpayment primarily resulted from PG&E remitting the applicable Departmental Power Charge at a rate of approximately $93.00/MWh, which exceeded rates identified in the CPUC-ordered rate schedule between the months of September and December 2003, as specified in Decision 03-09-018. This reimbursement is forecasted to be distributed to PG&E by March 2004.

In addition, through December 31, 2003 $23 million remained to be returned to customers in the SCE service area related to the $1 billion 2003 revenue requirement reduction.

Offsetting this reimbursement is $124 million in extraordinary revenues which the Department expects to receive, or has already received, during the 2004 Revenue Requirement Period. Of this $124 million, $38 million in interest, related to historical "WAPA" under-remittances, was received in February 2004. The $38 million in interest, as addressed in Commission Decision 04-01-049 as affirmed in Decision 04-02-065, is specifically related to PG&E's non-payment of applicable DWR charges associated with the delivery of energy to fulfill PG&E's "WAPA" obligations. For purposes of this Supplemental Determination, the remaining $86 million, related to "pre-petition" amounts (including interest) owed to the Department by PG&E, is expected to be received on April 14, 2004. The cumulative effect of these transactions is a net inflow to the Department of $46 million during the 2004 Revenue Requirement Period. This extraordinary revenue has been considered by the Department during the determination of its revenue requirements and applicable operating reserves for the 2004 Revenue Requirement Period.

EXTRAORDINARY COSTS

Within the September 18, 2003 Determination, and again within the March 10, 2004 Proposed Supplemental Determination, Departmental extraordinary costs (gas contract collateral deposits) for 2004 were estimated at $71 million. The $71 million amount was based on a required deposit of $71 million to an external hedging account maintained by the Department and was estimated using gas futures contracts to hedge June through December 2004 gas requirements. The estimate of $71 million has been revised to $37 million based on the required deposit of $71 million, as described earlier, less $34 million that remained on deposit in the external hedging account as of December 31, 2003. The final 2004 amount will be based on using gas hedges proposed by the investor-owned utilities who are administering the Department's contracts. These hedging arrangements were proposed to reduce exposure to a potentially volatile gas fuel supply market with potentially higher gas costs without these gas futures contracts.

BUNDLED CUSTOMER LOAD FORECASTS

The Department obtained the most recent forecasts of customer loads from each IOU in January 2004. The forecasts received from the IOUs were compared with other relevant information including recorded IOU sales data, utility expected growth factors, and forecasts prepared by the California Energy Commission ("CEC"). A loss factor was applied to the IOU estimates of sales at the customer's meter to obtain the total amount of energy required to meet customer electricity requirements. The loss factors utilized in developing the estimate of the electricity requirements are presented in Table E-1. Only SDG&E's loss factor is different from the September 18, 2003 Determination, where distribution losses were 4.0 percent. The increase to the SDG&E loss factor is based on new information received from the utility.

Table E-1
Loss Factors Utilized

Utility	Distribution	Transmission	Total
PG&E	6.4%	2.0%	8.4%
SCE	7.4%	1.6%	9.0%
SDG&E	4.6%	1.8%	6.4%

Each IOU forecast was developed using econometric models. The models rely on a statistical analysis of historical data to develop regression equations that relate changes in "independent" variables (such as employment growth) to "dependent" variables (such as electricity sales by the end-user segment). The resulting equations, together with forecasts of electricity prices, weather conditions, and key economic drivers, are used to predict sales by revenue class. To improve accuracy, the projections may be modified by the IOUs to account for current trends, judgment, or other events not specifically addressed in the models.

Table E-2 presents the major assumptions employed in the IOU forecasts utilized by the Department for the purpose of this 2004 Determination. The economic forecast for PG&E was based on a forecast of economic growth in PG&E's service area prepared by Economy.com. SCE derived its economic assumptions from statewide and county-specific forecasts (forecasts for each of the ten Southern California counties served by SCE were utilized by SCE during the determination of its economic assumptions) prepared by Global Insight in June 2003. These forecasts were modified by SCE to include employment data available through August 2003, resulting in a reduction in the construction and government employment categories. SDG&E relied on a forecast of economic trends in its service area prepared by Data Resource, Inc.

Table E-2
Major Assumptions Used in the Load Forecasts
of the Investor-Owned Utilities

	PG&E	SCE	SDG&E
Growth Assumptions:			
Population Growth [1, 2]	**1.1**	**1.1**	**1.4**
Number of Households [1, 2]	**1.4**	**1.3**	**1.7**
Non-Farm Employment [1, 2]	**0.6**	**0.7**	**2.1**
Heating Degree Days	**20-Yr. Avg.**	**30-Yr. Avg.**	**20-Yr. Avg.**
Cooling Degree Days	**20-Yr. Avg.**	**30-Yr. Avg.**	**20-Yr. Avg.**

[1] Percent per year increase during 2002 and 2003, except as noted.
[2] For SCE, values represent per year increase from 2003 to 2004.

The Department obtained each IOU's most updated load forecast as of February 2004. For PG&E, the Department relied on PG&E Advice Letter 2464-E, filed January 21, 2004, describing tariff changes required for its modified short-term procurement plan. For SCE, the Department relied on SCE's October 3, 2003 Energy Resource Recovery Account ("ERRA") filing. For SDG&E, the Department relied on SDG&E's Advice Letter 1557-E, filed January 20, 2004, describing revisions to its short-term procurement plan. PG&E projects 2004 total bundled sales of 78,499 GWh, an increase of 1.9 percent from the Department's September 18, 2003 Determination. SCE projects total bundled sales of 75,960 GWh, a decrease of 1.8 percent from the Department's September 18, 2003 Determination. SDG&E projects total bundled sales of 16,950 GWh, a decrease of .4 percent from the Department's September 18, 2003 Determination. These projections include transmission and distribution losses (i.e., at the generator).

EL PASO ENERGY SETTLEMENT AGREEMENT

On June 24, 2003, the State of California, Office of the Attorney General, executed a Master Settlement Agreement with El Paso Energy that will result in the reimbursement of $1.320 billion to California's electricity and natural gas ratepayers in addition to $125 million in savings off the Department's long-term power contract with El Paso Energy. Reimbursements will be provided in the form of both cash and non-cash consideration. Determinations regarding the manner in which this reimbursement will be allocated are the responsibility of the Commission.

At the time of the September 18, 2003 Determination, regulatory review of this settlement agreement was not yet complete and, as a result, the Department did not reflect potential extraordinary revenues in its forecasts. The Department has again reviewed the status of this settlement to determine the appropriateness of adjusting its revenue requirement.

The Master Settlement Agreement establishes conditions that must be satisfied prior to consummation of the settlement and distribution of funds. Several of the conditions have not yet been met. At this time, the Department is unable to predict when the proceeds will become available. Therefore, this Supplemental Determination does not incorporate any changes resulting from the El Paso Settlement Agreement.

DIRECT ACCESS AND CRS

In CPUC Decision 02-03-055, the Commission suspended the right of bundled load customers to elect direct access service after September 20, 2001. Electric end-users who elected to acquire electricity supplies from alternative providers on or before September 20, 2001 continue to be eligible for direct access service. In particular, Decision 02-03-055 prohibits the IOUs from accepting any new direct access service requests not already approved by the Commission, including requests from existing qualified direct access end-users that wish to add new direct access locations or accounts to their service[4][5], and contemplates the establishment of a surcharge on direct access customers. The direct access surcharge is intended to prevent cost shifting as a result of direct access migration prior to September 20, 2001[6].

On February 19, 2004, the Commission issued Decision 04-02-024 which allows current direct access customers to increase load at one or more locations provided that net load by the same customer does not increase within the utility service territory. This provision is intended to maintain the "standstill principle" adopted in Decision 02-03-055, while accounting for "normal changes in business operations[7]."

The Department's direct access estimates, which are based on data provided by the utilities in January 2004, are included in Table E-3. Based on the conditions imposed by CPUC Decisions 02-03-055, 02-11-022 and 03-05-034, the Department believes that direct access will continue at or near such levels in 2004. The Department regularly reviews each utility's monthly report to the Commission on current direct access load and service request changes, for any changes that would require action by the Department.

The direct access load percentages presented in Table E-3 differ slightly from the percentages presented in the September 18, 2003 Determination. Formerly, the Department estimated direct access as a percent of sales as 10.1 percent in PG&E's service territory, 14.0 percent in SCE's service territory and 16.6 percent for SDG&E's service territory.

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[4] Under Decision 04-02-024, issued February 19, 2004, the Commission will allow existing direct access load to add new load at a new location or on a new account so long as its net load in a given service territory does not increase.

[5] Direct access customers, however, may renew their direct access service contracts upon contract expiration or transfer such contract to a new service location provided the new and old load served are of comparable size.

[6] See discussion under Direct Access Surcharge Revenues, below.

[7] Decision 04-02-024, Finding of Fact 4.

Table E-3
Direct Access Percent of Load

	Percentage of Total Load
PG&E	10.8%
SCE	14.0%
SDG&E	16.9%
Statewide	12.9%

In a series of decisions the Commission has ordered certain classes of direct access and other departing load customers to pay a CRS related to historical stranded costs and ongoing uneconomic costs incurred by the IOUs and DWR to serve bundled customer load. The CRS comprises four components:

- DWR Bond Charge: charge for debt service associated with the Department's 2002 issuance of revenue bonds.

- DWR Power Charge: charge related to uneconomic DWR contract costs incurred by bundled load on an ongoing basis.

- Historical Procurement Charge ("HPC"): charge to recover SCE's historical under-collection of costs in 2000 and to recover PG&E's regulatory asset established PG&E's bankruptcy settlement with the Commission.

- Competition Transition Charge ("CTC"): charge related to uneconomic URG, QF, and purchased power agreement costs incurred by bundled customers on an ongoing basis.

Payments by direct access and other departing load of the DWR Bond Charge and the DWR Power Charge flow to the Department through Commission established rates on total usage. These revenues reduce one-for-one the bundled customer responsibility for the DWR Bond Charge and DWR Power Charge. DWR Power Charge collections from direct access, in particular, are limited by a maximum collections rate, or cap, however, of $.027/kWh, established by the Commission in Decision 03-07-030. Differences in the collection and accrual rate for the DWR Power Charge CRS are carried over for collection in future periods when the current period collections rate is less than the current period accrual rate.

The CRS does not affect Department power costs. The CRS is a revenue offset for a portion of costs associated with the bundled customer portfolio. With the exception of minor differences in the timing of revenue receipt between bundled customers and non-exempt direct access and other departing load customers, the revenue requirement in total is unaffected by the amount of the CRS.

DWR in consultation with the CPUC and the IOUs intends to quantify the expected revenues from direct access and other departing load customers which the Department expects to receive in 2004 after the CPUC allocation of this revenue requirement among the service territories of the IOUs.

CONTRACT DISPATCH AND COST MODELING

Subsequent to the September 18, 2003 Determination, various changes were made in the modeling of certain Department power contracts to reflect more current contract-related information. Other revised assumptions affecting the Department's total power costs, including increased fuel prices, are discussed below. Relevant contract changes are outlined in Table E-4:

Table E-4
Long-Term Contract Listing

Contract	Change
CalPeak Power—Panoche LLC	Changed to 51.5 MW from 48 MW, to reflect tested capacity
CalPeak Power—VacaDixon LLC	Changed to 50.8 MW from 48 MW, to reflect tested capacity
CalPeak Power—El Cajon LLC	Changed to 50.8 MW from 48 MW, to reflect tested capacity
CalPeak Power—Border LLC	Changed to 52 MW from 48 MW, to reflect tested capacity
CalPeak Power—Enterprise LLC	Changed to 51.3 MW from 48 MW, to reflect tested capacity
Calpine Energy Services, L.P. (Contract 3)	Changed the timing of capacity payments from annual, in-advance, lump-sum to monthly payments in arrears
Calpine Energy Services, L.P. (North San Jose Project)	Changed to 184 MW from a 180-225 MW range, to reflect tested capacity; assumed no increase to 225 MW during term of contract
GWF Energy LLC (Phases 1 and 2)	Changed to 191.5 MW from 176 MW to reflect tested capacity of these phases (94.8 MW and 96.7 MW)
GWF Energy LLC (Phase 3)	Changed to 170.5 MW from 164 MW, to reflect tested capacity
Sunrise Power Company, LLC	Changed to 572 MW from 560 MW to reflect tested capacity; update the capacity price to $173.43/kW-yr from $170.62, per contract Section 8.02(a)
Williams Energy Marketing & Trading	Corrected the scheduling coordinator fee to $16,667/month from $16,617/month, with escalation beginning June 2004

In addition, the costs assumed for the Amended and Restated Demand Reserves Purchase Agreement with the California Consumer Power Conservation and Financing Authority have been modified to more accurately reflect expected future costs associated with contract operation in light of historical capacity nomination patterns and costs, and a recent increase in the maximum capacity nomination limit. Annual costs associated with the Demand Reserve Purchase Agreement were originally forecasted to be $29.6 million in the September 18, 2003 Determination; these forecasted costs have been reduced in this Supplemental Determination to $26.1 million for 2004.

The aforementioned changes to modeled contract assumptions affect the Supplemental Determination by altering the amount of capacity available for dispatch by each IOU as well as the resultant contract costs incurred during IOU dispatch of Departmental power contracts. As a result of the relatively small net increase in dispatchable contract capacity, overall contract dispatches are not expected to change significantly as a result of these updated assumptions. All noted updates to specific contract capacity totals are based on current results of requisite annual performance testing.

Changes to specific fixed contract cost schedules did not have a material impact on forecasted contract cost totals during the 2004 Revenue Requirement Period. However, noted revisions, specifically the timing of capacity payments associated with Calpine Energy Services, L.P., Contract 3, are contributing components of noted deviations between actual and forecasted aggregate ending Power Charge Account balances as of December 31, 2003.

Table E-5
Net Short, Supply from Priority Long-Term Power Contracts, Off-System Sales and Residual Net Short in 2004

September 18, 2003 Filing

Period	Net Short (GWh)	Supply from Long-Term Priority Contracts (GWh)	Priority Long-Term Power Contract Costs (Millions of Dollars)	Off System Sales Volumes (GWh)	Revenues from Off System Sales (Millions of Dollars)	(Residual Net Short) Spot Volume (GWh)
Q1-2004	11,187	14,061	$1,110	(4,369)	$112	1,495
Q2-2004	11,406	13,253	1,043	(3,468)	82	1,622
Q3-2004	15,842	16,175	1,305	(3,169)	86	2,837
Q4-2004	14,399	15,310	1,205	(4,969)	152	4,058
Total	52,834	58,798	4,663	(15,976)	433	10,011

Supplemental Filing For 2004

Period	Net Short (GWh)	Supply from Long-Term Priority Contracts (GWh)	Priority Long-Term Power Contract Costs (Millions of Dollars)	Off System Sales Volumes (GWh)	Revenues from Off System Sales (Millions of Dollars)	(Residual Net Short) Spot Volume (GWh)
Q1-2004	11,467	14,675	$1,139	(4,939)	$214	1,731
Q2-2004	11,432	13,972	1,124	(4,816)	180	2,276
Q3-2004	15,888	17,436	1,371	(4,070)	175	2,523
Q4-2004	15,193	16,145	1,245	(5,513)	268	4,560
Total	53,980	62,228	4,879	(19,338)	838	11,090

Total power costs are also dependent upon updated assumptions related to the Department's fuel price forecast. These changes are discussed below.

NATURAL GAS PRICE FORECASTS AND RELATED ASSUMPTIONS

The natural gas forecast underpinning this Supplemental Determination includes gas prices that are considerably above those that were used in the September 18, 2003 Determination. While previous forecasts included price increases that were dampened after the first few years of the forecast, the increase associated with the February 2004 Gas Price Forecast projects price increases over a longer term. In many respects, this forecast appears to reflect a structural shift in gas prices in later years. Table E-6 illustrates the updated price forecast.

Table E-6
Natural Gas Average Price Forecasts
($/MMBtu – Nominal)

	Southern California Border		**PG&E Citygate**	
	2004	**2005**	**2004**	**2005**
January	$5.37	$5.38	$5.53	$5.55
February	$4.58	$4.59	$4.72	$4.74
March	$4.42	$4.43	$4.56	$4.57
April	$4.67	$4.68	$4.82	$4.83
May	$4.94	$4.96	$5.10	$5.11
June	$5.00	$5.01	$5.15	$5.16
July	$4.88	$4.90	$5.03	$5.05
August	$4.54	$4.55	$4.68	$4.69
September	$4.67	$4.69	$4.82	$4.83
October	$4.80	$4.81	$4.95	$4.96
November	$5.14	$5.16	$5.30	$5.32
December	$5.08	$5.09	$5.24	$5.25
Annual Average	**$4.84**	**$4.85**	**$4.99**	**$5.01**

Using the same Long-Term Price Model that has been used in all prior revenue requirement filings, the forecast reflects new demand data supplied from the U.S. Energy Information Administration (EIA), lagged actual historical prices, and a storage variable adjusted for weather conditions to project prices at Henry Hub, Louisiana. Henry Hub is the physical location used to trade gas futures contracts on the New York Mercantile Exchange (NYMEX) and is generally recognized as the most important market hub in North America. The variables have been chosen for their statistical significance when compared to historical prices. The main variables used by the model, are used in determining an econometric equation that has proved to be reliable in terms of predicting annual prices against actual reported prices. From the base annual price forecast, monthly prices are then derived using historical "spread factors" or the historical relationship of actual seasonal prices. Finally, the Henry Hub base forecast price is correlated to California as well as to western border and hub locations to forecast prices used in the revenue requirements process.

The model accounts for the historical shift upwards in gas prices that continued to linger over the course of 2003 compared to previous years. This shift reflects the exceedingly high gas prices in the first quarter of 2003, which were partially the result of the near record cold experienced in the northeast United States and the upper mid-western regions of the United States during the winter of 2002-2003. For each month, prices at Henry Hub in 2003 increased over $2.00 from the same prices for 2002. Short-term factors tended to support historically high 2003 gas prices. Storage levels that were drawn down in the spring of 2003 to below "normal" levels (the lowest levels since 2001) served to support strong prices into the summer. As the year progressed, high prices tended to encourage substitution of fuel other than natural gas and efficiency gains in new natural gas-fired generation allowed storage to attain near normal levels. Throughout the year, however, high residual fuel oil prices and overall national economic activity offset significantly reduced natural gas demand. At the end of 2003, warmer-than-normal weather during November and December appeared to assure a repeat of the prior winter's price reductions, but this reduction did not occur as. All these factors tend to support higher prices for the 2004 gas forecast.

Increased gas prices impact the Department's revenue requirement in a number of ways, including increased contract costs for those contracts that have variable fuel costs (tolling arrangements). Gas prices also create potential increases or decreases in dispatch and retail sales volumes for those contracts that have variable fuel costs, potential increases in dispatch and retail sales volumes for those contracts that do not have variable fuel costs (fixed price, dispatchable contracts), and potential increases in retail sales volumes for those contracts that do not have variable fuel costs (fixed price, must take contracts). Thus, the increased fuel cost component of the Department's power supply contract costs constitutes a critical factor for the increase in total power costs from $4.698 billion (as estimated in the September 18, 2003 Determination) to $4.860 billion in this Supplemental Determination.

IOU PLANNED OUTAGE SCHEDULES

New information regarding planned outages in 2004 at PG&E's Diablo Canyon nuclear generation facility was provided to the Department by PG&E on February 27, 2004. As a result of this new information, the Department has revised the planned outages assumed for Diablo Canyon Units 1 and 2 (with a 1,087 MW capacity per unit) within the Department's production simulation analysis supporting this Determination, which is included within the administrative record.

In the September 18, 2003 Determination, Diablo Canyon Unit 1 was projected to incur a planned maintenance outage modeled to begin in April 2004, for an expected outage period of 35 days. Based on the updated information provided by PG&E, Diablo Canyon Unit 1 is now projected to incur a planned maintenance outage modeled to begin in April 2004, for an expected outage period of 48 days.

In the September 18, 2003 Determination, Diablo Canyon Unit 2 was projected to incur a planned maintenance outage modeled to begin in October 2004, for an expected outage period of 35 days. Based on the updated information provided by PG&E, Diablo Canyon Unit 2 is now projected to incur a planned maintenance outage modeled to begin in November 2004, for an expected outage period of 42 days.

Changes in planned outages can impact the projected dispatch of units in the region and can also impact the amount of sales of DWR contract energy to retail customers.

During the administrative process examining the Proposed Supplemental Determination issued on March 10, 2004, it became apparent the PROSYM data provided to the IOUs did not reflect the outage assumptions identified above but rather included extended outages for Diablo Canyon. This discrepancy has been corrected in this Supplemental Determination and in the underlying PROSYM data.

HYDROELECTRIC CONDITIONS IN CALIFORNIA AND THE PACIFIC NORTHWEST

The outlook for 2004 hydro-electric conditions in California and the Pacific Northwest has changed twice since the September 18, 2003 Determination. In consideration of the potential impact, the Department reviewed its hydroelectric assumptions, and updated its forecast to reflect current expected hydroelectric conditions in both geographic areas. This update was included within the administrative record supporting the Department's March 10, 2004 Proposed Supplemental Determination. As a result of the comments received, the Department has updated this Determination to include revised information provided by the IOUs.

In the September 18, 2003 Determination, hydroelectric facilities in California and the Pacific Northwest were expected to operate based on normal water years in 2004 and 2005.

Following an analysis of precipitation and snow-pack conditions as of February 1, 2004, the CEC prepared an in-state hydro outlook that indicated annual hydroelectric production levels at 91 percent of normal for 2004. This California forecast was predicated on normal precipitation conditions for the remainder of the year. For the Pacific Northwest, the Department utilized the National Weather Service's Northwest River Forecast Center runoff forecast for The Dalles, February 2004 Final Forecast. This updated forecast was 93 percent of a normal year in 2004. Based on those hydro forecasts, the Department updated its adopted forecast to 92 percent of normal, WECC-wide, for 2004.

Comments received during the administrative process addressing the Proposed Supplemental Determination provided an additional month of data, including updated snow pack assessments. The Department has updated its hydro-electric forecast assumptions for 2004 based on information provided by SCE and PG&E. The new assumptions are 86 percent of normal in southern California, 100 percent of normal in Northern California and 92 percent in the Northwest.

Both California and the Pacific Northwest are assumed to be at 100 percent of normal hydroelectric production in 2005.

F. JUST AND REASONABLE DETERMINATION

BACKGROUND

THE AUGUST 16, 2002 DETERMINATION

The Department's August 16, 2002 Determination of Revenue Requirements provided a discussion supporting the determination by the Department that its revenue requirement for 2003 was just and reasonable. That information is, to the extent applicable and not modified herein, incorporated in this 2004 Supplemental Determination by reference and will not be repeated herein.

THE JULY 1, 2003 SUPPLEMENTAL DETERMINATION

Subsequent to August 16, 2002, new information became available to the Department. Such new information, either provided by the IOUs, as a result of experience from actual data relevant to the Department's power purchase program, or emanating from a change in certain assumptions, led to the 2003 Supplemental Determination. That information supported the Department's determination that its 2003 Supplemental Determination was just and reasonable and is, to the extent applicable and not modified herein, incorporated in this 2004 Supplemental Determination.

THE SEPTEMBER 18, 2003 DETERMINATION

The September 18, 2003 Determination provided extensive material leading to the determination by the Department that its revenue requirement for 2004 was just and reasonable. That information is, to the extent applicable and not modified herein, incorporated in this 2004 Supplemental Determination.

THE 2004 SUPPLEMENTAL REVENUE REQUIREMENT DETERMINATION

In February 2004, with the availability of a substantial amount of the actual data for 2003, the Department identified a year-end 2003 balance in the Power Charge Operating Account that was $275 million greater than the year-end 2003 balance projected in the September 18, 2003 Determination. In connection with CPUC hearings on the allocation of the 2004 revenue requirement, the Department provided and discussed this data in Reference Item C, which identified the year-end 2003 Power Charge Account Balances. Reference Item C also notified the CPUC that the Department was currently examining the ending Operating Account balance along with updated gas prices, expected gas hedging activity, current hydroelectric generation conditions, the anticipated payment from PG&E of interest on under-remittances associated with energy delivered by PG&E to the Western Area Power Administration and other variables including, but not limited to, payments to the Department that may occur in connection with PG&E's emergence from bankruptcy.

To obtain additional information to consider whether to issue a 2004 Proposed Supplemental Determination, the Department submitted two sets of data requests to each of the three IOUs. The responses provided by the IOUs were considered in the Department's examination of its 2004 revenue requirements. [8]

The Department's examination of the issues identified above allowed the Department to determine that it should institute a public process to examine modifications to the Department's 2004 revenue requirements. A description of this analysis is found in Section G of this determination.

As a result of the review process, the Department published a Proposed Supplemental Determination of Revenue Requirements for public review and comment on March 10, 2004, with comments due by April 1, 2004, consistent with applicable regulations.

PUBLIC PARTICIPATION IN THE SUPPLEMENTAL DETERMINATION

During the comment cycle commencing on March 10, 2004 and ending on April 1, 2004, the Department received questions from PG&E and from SDG&E concerning the Proposed Supplemental Determination and underlying data. The Department responded to these questions to assist interested persons in the review of the Proposed Supplemental Determination.

Comments on the Proposed Supplemental Determination were timely received from PG&E and from SDG&E on April 1, 2004. No other comments were received by the Department. The Department reviewed and evaluated each comment to determine the potential impact on the revenue requirement. As a result of the review process the Department has determined certain changes to the Proposed Supplemental Determination are appropriate. These changes include, but are not limited to, assumptions related to Diablo Canyon outages and to hydro-electric conditions. The assumptions underlying this Supplemental Determination are found in Section E. Following is a summary of each of the issues raised by PG&E and by SDG&E and the Department's response.

PG&E 4/01/04 Comment 1: DWR's Revised Modeling Over-Estimates The Effect Of The Diablo Canyon Refueling Outages

Response: The Diablo Canyon projected outage assumption in DWR's modeling for 2004 has been corrected.

PG&E 4/01/04 Comment 2: DWR's Revised Modeling Underestimates The Availability Of Hydroelectric Generation

Response: The Department agrees and has revised the hydro-electric forecast for 2004 to increase projected hydro-electric output in the northern Sierra area.

[8] See Section G herein for reference to the actual questions posed in the data request. The IOUs' responses contain confidential information and are included within the administrative record supporting this Supplemental Determination subject to applicable nondisclosure requirements.

PG&E 4/01/04 Comment 3: The Santa Cruz Landfill Project No Longer Sells Power To DWR

Response: The Department has removed this resource from the projections supporting this Supplemental Determination. This results in a reduction of 25.9 GWh and a total cost reduction of $1,683,800.

PG&E 4/01/04 Comment 4: DWR Should Include The Expected Cash Benefits Of The "El Paso Settlement" In Its 2004 Power Charge Revenue Requirement Estimate

Response: In the Proposed Determination the Department explained that on June 24, 2003, the State of California, Office of the Attorney General, executed a Master Settlement Agreement with El Paso Energy that will result in the reimbursement of $1.320 billion to California's electricity and natural gas ratepayers in addition to $125 million in savings off the Department's long-term power contract with El Paso Energy. Reimbursements will be provided in the form of both cash and non-cash consideration. Determinations regarding the manner in which this reimbursement will be allocated are the responsibility of the Commission.

The Department has reviewed the status of the Master Settlement Agreement to determine the appropriateness of adjusting the Department's revenue requirement to reflected projected reimbursements.

The Master Settlement Agreement establishes conditions that must be satisfied prior to consummation of the settlement and distribution of funds. Several of the conditions have not yet been met. (See CPUC Decision 04-02-062 at p. 30: "It is not clear that DWR will receive consideration from the El Paso settlement this year [2004] . . . .The San Diego Superior Court order approving the El Paso settlement in Natural Gas Anti-trust Cases I, II, III, & IV, J.C.C.P. Nos. 4221, 4334, 4226, & 4228 was appealed on February 3, 2004.") At this time, the Department is unable to predict when the proceeds will become available. Therefore, no changes resulting from the El Paso Settlement Agreement have been included in this Supplemental Determination. To the extent that DWR receives consideration as a result of the Master Settlement Agreement with El Paso Energy, the Department will reduce the amounts which contribute to its revenue requirements by the amount of consideration received from El Paso. This reduction will be implemented through future revenue requirement determinations. (See CPUC Decisions 04-02-062 at pp. 27-30 and 03-10-087 at pp. 7-11.)

PG&E 4/01/04 Comment 5: DWR's Methodology For Incorporating Collateral For Gas Hedging Into Its PCRR Results In Double Counting The Costs Of Natural Gas

Response: Fuel price hedging is not explicitly modeled in the determination of the Department's revenue requirements. Hedging activities for DWR long-term contracts are directed and executed by the IOU to which each contract is allocated for operational and administrative purposes. While the IOUs submit fuel plans for the contracts to the CPUC, the IOUs are not required to identify volumes that are expected to be hedged, the price at which any fuel volumes are expected to be hedged, or the time period over which fuel volumes will be hedged. Providing this level of flexibility in a proposed hedging program is not unusual and is intended to allow the IOUs to optimize hedging strategies for the benefit of the ratepayers.

This very flexibility, however, precludes the Department from accurately projecting potential future hedge activities (both financial and forward physical purchase) in the determination of its revenue requirements. At this time, the Department cannot accurately represent the various hedging strategies that the IOUs may choose to employ in the future, nor can the Department predict what price levels the IOUs may be able to achieve under the hedging strategies they might undertake. In addition, the IOUs' hedging activities to date have been short-term in nature, generally employing financial hedges two to three months in the future, providing little input to the development of an annual revenue requirement determination.

What the Department can do, and does, in the development of its revenue requirement determination, is address the issue of fuel price volatility through sensitivity cases that are used, in part, to determine the required size of the Operating Reserve Account (see page 10 of the March 10, 2004 Proposed Supplemental Determination of Revenue Requirements and pages 37 and 38 of the September 18, 2003 Determination of Revenue Requirements). In addition, the IOUs provide information to the Department on the hedges that they do enter as those transactions occur. The Department tracks this information and compares it to fuel price assumptions contained within the current revenue requirement to determine the adequacy and efficiency of the current revenue requirement.

Theoretically, the ability of the IOUs to hedge fuel prices could lead to a ceiling on the seven-month volatility calculation that is used, in part, to determine the required size of the Operating Reserve Account. If the IOUs were to actually enter into hedges that limited the potential fuel price increase that could apply to DWR contract fuel costs at a level below that which is projected in the Stress Case, the cash flow volatility that is calculated would be less than that which is currently calculated. As noted earlier, however, the flexibility of the hedging programs that the IOUs currently undertake, along with the current short-term nature of hedges they have entered into, preclude the Department from reasonably estimating such a ceiling.

Perhaps more important is the fact that such a calculation would not necessarily lead to a lower Operating Reserve Account requirement. As defined in the Indenture, the Operating Reserve Account Requirement is calculated, in respect of each Revenue Requirement Period, as "the greater of (a) the largest aggregate amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any consecutive seven calendar months commencing in such Revenue Requirement Period and (b) ...12 percent of the Department's projected annual Operating Expenses for any Revenue Requirement Period...provided, however, that...the projected amount will not be less than the applicable percentage of Operating Expenses for the most recent 12-month period for which reasonably full and complete Operating Expense information is available...adjusted in accordance with the Indenture to the extent the Department no longer is financially responsible for any particular Power Supply Contract". Even without a theoretical reduction in a gas price ceiling for contract fuel costs incurred under the Stress Case, the governing clause that applies to the current Operating Reserve Account Requirement is as follows: "12 percent of the Department's projected annual Operating Expenses". Therefore, any reduction in the gas price ceiling that could result from hedging activities would not impact the sizing of the Operating Reserve Account.

The fact that the Operating Reserve Account may not experience a reduction as a result of hedging activities does not mean that the hedging activities are not useful in containing DWR contract costs. Hedging programs implemented by the IOUs can contain fuel price increases and provide some level of insurance against higher-than-anticipated fuel costs. In this respect, the cost of maintaining hedging accounts and the expenses estimated to maintain those accounts are a reasonable cost of doing business that ultimately help the Department and the IOUs in their goal of managing costs that are passed on to the ratepayers.

The hedging account expense in this Supplemental revenue requirement Determination of $71 million is arrived at by analyzing the NYMEX margin requirements to secure futures on the highest seven months of fuels requirements. Margin requirements of the NYMEX exchange are listed by the exchange. The Department estimates the entire cost of the hedging account at the beginning of the revenue requirement period.

As needed, the Department deposits monies into its brokerage account enabling gas hedging transactions. Since these amounts are not available to pay other operating expenses, they are not deemed to be part of the Operating Account and are not used to meet the Indenture required minimum balance for the Operating Account.

Rather, these funds on deposit at the brokerage serve as a reserve account that enables timely hedges by the IOUs to protect the ratepayers from volatility and rapidly increasing gas prices. If the hedges decrease the actual cost of gas realized by the Department such benefit is reflected in the cash balance in the Operating Account. In each revenue requirement the Department uses the beginning cash balance of the Operating Account to determine the amounts to be collected through its revenue requirement. To the extent that the Operating Account balance is increased by lowered gas costs or unused hedging account deposits, all else being equal, the Department is able to reduce its revenue requirement, thereby returning to ratepayers any favorable effect from gas hedging.

The Department recognizes that this approach is conservative (i.e. the actual cost is more likely to be less than the projection than it is to be more than the projection), but the Department also recognizes that the ongoing revenue requirement process keeps actual costs at the appropriate level. For reasons described earlier (primarily the inability to project the timing and amount of hedging costs under the IOUs flexible hedging programs), the Department has determined that the projected expense, and its cash flow treatment, is reasonable.

As also noted in Sections C and E, the Department still has $34 million on deposit in its hedging account that was not used in 2003. This amount will remain on deposit, but only an additional $37 million will need to be provided from the Operating Account in 2004 to meet the Department's estimated deposit requirement of $71 million. This action decreases the 2004 Extraordinary Cost by $34 million from that estimated in both the 2004 Determination and the 2004 Proposed Supplemental Determination.

PG&E 4/01/04 Comment 6: It Does Not Appear That DWR Has Incorporated The Below Market "Williams Gas" In Its Estimate Of Gas Costs

Response: DWR does not account for the difference in its gas forecast and Williams contract gas price. Current PROSYM modeling uses a commodity gas price with delivery points at PG&E Citygate and the southern California border to estimate natural gas costs associated with DWR's contracts. DWR is examining a contract by contract gas price forecast that will include not only the commodity price, but contract specific terms and distribution charges for use in connection with its 2005 revenue requirement determination. However, this analysis is not yet complete nor is it part of the administrative record supporting this Supplemental Determination.

If the realized cost of gas is lower than forecast, the decreased costs are reflected in the cash balance in the Operating Account. In each subsequent revenue requirement the Department uses the cash balance of the Operating Account to determine the amounts to be collected through its revenue requirement. To the extent that the Operating Account balance is increased by lower gas costs, all else being equal, the Department is able to reduce its revenue requirement, thereby returning to ratepayers any favorable effect from lower gas costs. Until the Department has had the opportunity to establish the contract by contract gas price forecast noted in the previous paragraph, the Department will continue to project all gas costs consistent with the gas forecast at PG&E Citygate and the southern California border, and "true-up" actual gas costs (both higher and lower than forecast) as a part of subsequent revenue requirement determinations.

PG&E 4/01/04 Comment 7: DWR Has Not Adequately Explained Its $59 Million Estimate Of Administrative And General Costs

Response: As a base for developing its A&G costs for the 2004 revenue requirement, DWR used its 2003-2004 fiscal year budget appropriation as passed by the Legislature, and signed by the Governor. DWR used the same amount for the 2004 calendar year as was used for the State budget's fiscal year ending June 30, 2004. This is appropriate as it is anticipated that A&G costs are incurred evenly throughout the year, and there are no expected significant increases or decreases to be incurred in calendar 2004 as compared to the 2003-2004 fiscal year.

$28 million of the A&G costs are for pro rata charges. The pro rata costs for services provided by other agencies of the State are in addition to the direct A&G costs which DWR has paid in prior years and will continue to pay in 2004. PG&E is correct in stating that $14 million of the pro rata charges to be paid in calendar 2004 are attributable to prior years pro rata charges that had not been previously allocated to DWR. However, it is appropriate to include them in the 2004 revenue requirement as the cash payment for the services will be made in 2004.

The $28 million pro rata charge for other state agencies costs to be reimbursed by various state programs is determined by the State Department of Finance, a separate department within the State. A general overview of the Department of Finance's development of pro rata charges, the agencies being reimbursed through the pro rata charge, as well as the details of the calculation and allocation applicable to DWR and its Electric Power Fund, can be found on the Department of Finance's web site starting at www.dof.ca.gov/FISA/PROSWCAP/general_overview.htm. These pro rata costs are allocated directly to the Power Supply Program through the State's budgetary process and are paid by the Power Supply Program.

Each quarter the State Controller's Office initiates a transfer of approximately $7 million from the Power Supply Program's Operating Account to pay for the Power Supply Program's pro rata charges.

PG&E 4/01/04 Comment 8: DWR Continues To Use Overly-Conservative Assumptions To Calculate Its Required Reserve Levels, Resulting In Likely Overstatement Of Those Requirements

Response: Only those assumptions that are necessary to satisfy the requirements of the financing documents are used in calculating the required reserve amounts. In the case of the Debt Service Reserve Account, the reserve is calculated as equal to the Maximum Annual Aggregate Debt Service over the life of the bonds.[9] For the 2004 Determination of Revenue Requirements (and unchanged in this 2004 Supplemental Determination of Revenue Requirements), this amount is calculated at $927 million.

In the case of the Operating Reserve Account, the Operating Reserve Account Requirement is calculated as "the greater of (i) the largest aggregate amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any consecutive seven calendar months commencing in such Revenue Requirement Period and (ii) ...12 percent of the Department's projected annual Operating Expenses for any Revenue Requirement Period...provided, however, that...the projected amount will not be less than the applicable percentage of Operating Expenses for the most recent 12-month period for which reasonably full and complete Operating Expense information is available...All projections referenced in this paragraph shall be based on such assumptions as the

[9] Trust Indenture, October 1, 2002, page 9.

Department deems to be appropriate after consultation with the Commission and, in the case of clause (i) above, may take into account a range of possible future outcomes".[10]

The Department operates with the objective of minimizing the revenue requirement while still complying with its duties to bondholders. To this end, the Department identifies several plausible assumptions that are intended to provide stress to the Power Charge and Bond Charge Accounts. While the Department must make the final determination regarding the plausibility and reasonableness of the assumptions that are used in the Stress Cases, it has consulted with the Commission and has considered – and will continue to consider in future determinations – comments and inputs from other parties relating to the assumptions that are used.

Notwithstanding the Department's belief that the assumptions that underlie, the development of the Operating Reserve Account are appropriate, the current Stress Case assumptions do not, in this case, directly impact the calculation of the Operating Reserve Account Requirement -- effectively mooting the point of PG&E's comment. As described in the second paragraph of this response, the Operating Reserve Account Requirement is calculated using the greater of a two-pronged test. Even without a "relaxation" of the assumptions underlying the Stress Case, the governing clause that applies to the current Operating Reserve Account Requirement is the "12 percent of the Department's projected annual Operating Expenses". Therefore, any further "relaxation" of the assumptions underlying the Stress Case would not impact the size of the Operating Reserve Account Requirement.

In the case of the Minimum Operating Expense Account Balance, it is calculated as "...the maximum amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any one calendar month during that Revenue Requirement Period. Such projections shall be based on such assumptions as the Department deems to be appropriate after consultation with the Commission and may take into account a range of possible future outcomes"[11] Therefore, as was the case with the determination of the Operating Reserve Account Requirement, the assumptions necessary to satisfy the requirements of the financing documents are determined by the Department.

PG&E 4/01/04 Comment 9: DWR's reduction in its 2004 power charge revenue requirement is intertwined with the true up of DWR's 2003 power charge revenue requirement

Response: DWR is supplying historic 2003 operating data to allow parties to properly calculate the 2003 true up amounts.

[10] Trust Indenture, October 1, 2002, pages 12-13.
[11] Trust Indenture, October 1, 2002, page 11

SDG&E 4/01/04 Comment 1: SDG&E has observed significant differences in the forecast output of the dispatachable contracts of the Department that have been allocated to SDG&E. The output forecasted in both Prosym 44 and 45 is significantly more than the output forecast in Prosym 43 that supported the Department's initial 2004 determination. SDG&E requests that the Department explain what caused this significant increase in forecast output.

Response: The increase in forecasted output of the dispatchable contracts is due to the following factors:

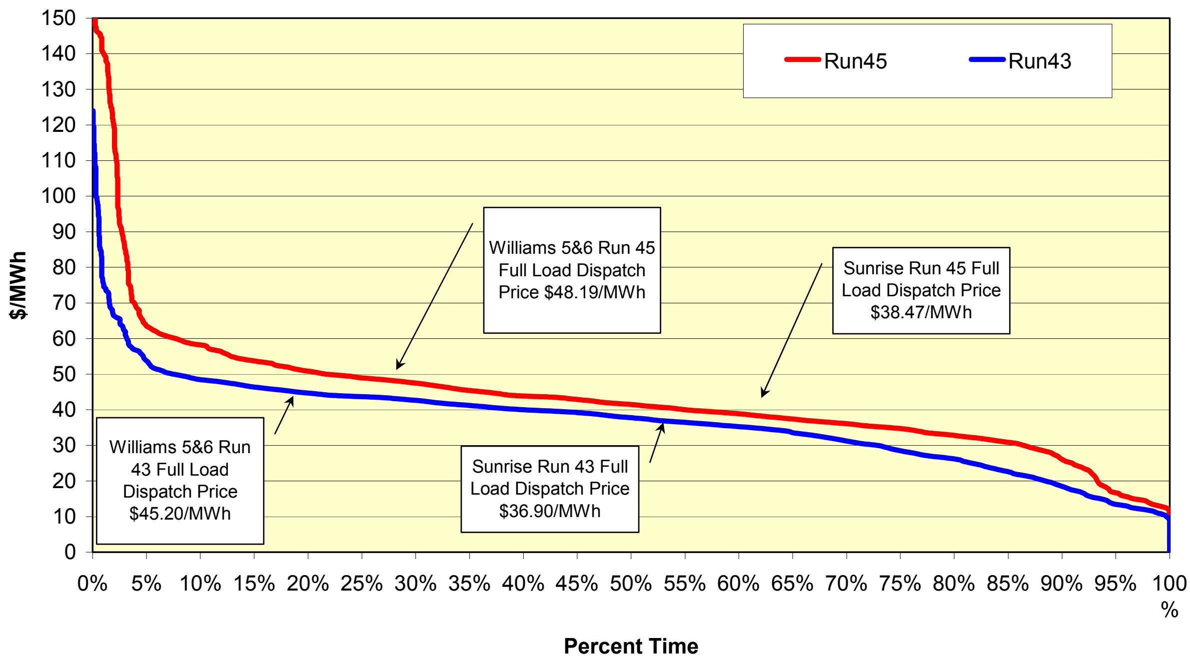
In PROSYM Run 45, the demand forecast for WECC regions outside of California was updated consistent with the latest WECC projections. Demands are generally higher with this update. The increase in projected electricity demand in Arizona, Nevada, and New Mexico was of greater relative magnitude than in other WECC regions

Under PROSYM Run 45, projected natural gas prices throughout the WECC are higher than under PROSYM Run 43. This fact leads to higher projected energy market spot prices in almost all hours, as natural gas is the marginal fuel in most time periods.

With higher projected natural gas prices, the dispatch price of Sunrise and Williams D resources also increase in PROSYM Run 45, however the relative increase is less than the relative increase in energy market spot prices. This situation increases the relative dispatch of the Sunrise and Williams D resources, as they are in merit with greater frequency under PROSYM Run 45 (see Price Duration Curve Comparison tab of PROSYM Run 45.)

With higher spot market prices throughout the WECC, the Sunrise unit (and to a lesser extent the Williams D resources) are also subject to increased dispatch as a result of the heat rate advantage relative to the on-peak and average spark-spreads projected in spot energy markets.

Comparison of Price Duration Curves (Runs 43 and 45)



The full text of the PG&E and SDG&E comments on the Department's March 10, 2004 Proposed Supplemental Determination, are included in Section G.

JUST AND REASONABLE DETERMINATION

The Department, having reviewed all comments provided, and having updated certain information as identified previously in this Determination, has determined the Supplemental Determination of Revenue Requirement for the period of January 1, 2004, through December 31, 2004, is just and reasonable.

G. ANNOTATED REFERENCE INDEX OF MATERIALS UPON WHICH THE DEPARTMENT RELIED TO MAKE DETERMINATIONS

Volume	Record Number	Record Title
DWR04psRR	1	State of California Department of Water Resources Determination of Revenue Requirements for the Period January 1, 2004 through December 31, 2004, including by reference materials contained within Section I - Annotated Reference Index of Materials Upon Which the Department Relied to Make Determinations, Dated September 18, 2003

Volume	Record Number	Record Title
DWR04psRR	2	Pacific Gas and Electric Company's First Set of Data Requests of the California Department of Water Resources 2004 Revenue Requirement Determination A.00-11-056, Dated September 29, 2003
DWR04psRR	3	Southern California Edison Company's First Set of Data Requests of the California Department of Water Resources 2004 Revenue Requirement Determination A.00-11-038, Dated October 1, 2003
DWR04psRR	4	Southern California Edison Company's Second Set of Data Requests of the California Department of Water Resources 2004 Revenue Requirement Determination A.00-11-038, Dated October 17, 2003
DWR04psRR	5	Southern California Edison Company's Third Set of Data Requests of the California Department of Water Resources 2004 Revenue Requirement Determination A.00-11-038, Dated November 24, 2003
DWR04psRR	6	Southern California Edison Company's Fourth Set of Data Requests of the California Department of Water Resources 2004 Revenue Requirement Determination A.00-11-038, Dated January 29, 2004
DWR04psRR	7	State of California Department of Water Resources Responses to Data Requests from Interested Parties in Application 00-11-038 et al. before the California Public Utilities Commission (2004 Determination of Revenue Requirement) [Includes responses to Pacific Gas & Electric Companies First Set of Data Requests and Southern California Edison Company's First Set of Data Requests], Dated October 7, 2003
DWR04psRR	8	State of California Department of Water Resources Responses to Data Requests from Interested Parties in Application 00-11-038 et al. before the California Public Utilities Commission (2004 Determination of Revenue Requirement) [Includes responses to Southern California Edison Company's Second Set of Data Requests], Dated October 21, 2003
DWR04psRR	9	State of California Department of Water Resources Responses to Data Requests from Interested Parties in Application 00-11-038 et al. before the California Public Utilities Commission (2004 Determination of Revenue Requirement) [Includes responses to Southern California Edison Company's Third Set of Data Requests], Dated December 8, 2003
DWR04psRR	10	State of California Department of Water Resources Responses to Data Requests from Interested Parties in Application 00-11-038 et al. before the California Public Utilities Commission (2004 Determination of Revenue Requirement) [Includes responses to Southern California Edison Company's Fourth Set of Data Requests], Dated February 10, 2004

Volume	Record Number	Record Title
DWR04psRR	11	California Department of Water Resources First Data Request to Pacific Gas & Electric Regarding 2004 Revised Sales Forecasts and 2004 Hydrological Conditions, Dated February 18, 2004
DWR04psRR	12	California Department of Water Resources First Data Request to Southern California Edison Regarding 2004 Revised Sales Forecasts and 2004 Hydrological Conditions, Dated February 18, 2004
DWR04psRR	13	California Department of Water Resources First Data Request to San Diego Gas & Electric Regarding Revised Sales Forecasts, Dated February 18, 2004
DWR04psRR	14	California Department of Water Resources Second Data Request to Pacific Gas & Electric Company Regarding Nuclear Operations and Other Generation, Dated February 24, 2004
DWR04psRR	15	California Department of Water Resources Second Data Request to Southern California Edison Regarding Nuclear Operations, Dated February 24, 2004
DWR04psRR	16	California Department of Water Resources Second Data Request to San Diego Gas & Electric Regarding Nuclear Operations February 24, 2004
DWR04psRR	17	CONFIDENTIAL - Pacific Gas and Electric Company's Response to California Department of Water Resources First Data Request, Dated February 25, 2004 – NOT FOR PUBLIC RELEASE
DWR04psRR	18	CONFIDENTIAL - Pacific Gas and Electric Company's Partial Response to California Department of Water Resources Second Data Request, Dated February 27, 2004 – NOT FOR PUBLIC RELEASE
DWR04psRR	19	CONFIDENTIAL - Pacific Gas & Electric Company's Response to California Department of Water Resources Third Data Request, March 1, 2004 – NOT FOR PUBLIC RELEASE
DWR04psRR	20	CONFIDENTIAL - San Diego Gas & Electric Response to California Department of Water Resources First Data Request, Dated March 1, 2004 - NOT FOR PUBLIC RELEASE
DWR04psRR	21	CONFIDENTIAL - San Diego Gas & Electric Response to California Department of Water Resources Second Data Request, Dated March 1, 2004 – NOT FOR PUBLIC RELEASE
DWR04psRR	22	CONFIDENTIAL - Southern California Edison Responses to California Department of Water Resources First Data Request, Dated March 5, 2004 – NOT FOR PUBLIC RELEASE

Volume	Record Number	Record Title
DWR04psRR	23	Pacific Gas & Electric Company's Request for Reconsideration of September 18, 2003 DWR Notice of Determination of Revenue Requirement, Dated September 29, 2003
DWR04psRR	24	Prehearing Conference Statement of San Diego Gas and Electric Company, Dated September 30, 2004
DWR04psRR	25	Motion to Bifurcate of San Diego Gas and Electric Company and Motion of San Diego Gas and Electric Company for an Order Shortening Time to Respond to the Motion to Bifurcate, Dated September 30, 2004
DWR04psRR	26	Reply Testimony of the Office of Ratepayer Advocates Relating to the True-Up of the DWR 2001-2002 Revenue Requirement Allocation, A.00-11-038, A.00-11-056, and A.00-11-028, including Qualifications and Prepared Testimony of Steve Ross, Dated October 22, 2003
DWR04psRR	27	Southern California Edison Rebuttal Testimony Regarding the Implementation of DWR's 2004 Revenue Requirement and True-Up of DWR's 2001-2002 Revenue Requirement A.00-11-038, Exhibit No: SCE-20, Witnesses: C Cushnie, A. Jazayeri, Rosemead, California, Dated October 22, 2003
DWR04psRR	28	State of California Department of Water Resources Reply Testimony of James E. Olson and Frank J. Perdue in A. 00-11-038 et al. Before the California Public Utilities Commission 2004 Determination of Revenue Requirements Allocation True up for 2001-2002 Revenue Requirements Period, including Exhibit 1 Power Purchase Summary 2001 through 2002, and Exhibit 2 Power Purchase Summary 2001 through 2002 (HAFs Method), Dated October 22, 2003
DWR04psRR	29	Pacific Gas & Electric Company 2004 Revenue Requirement Reply Testimony, A.00-11-056, Witness Nina B. Bubnova, Dated October 22, 2003 Testimony includes exhibits: Pacific Gas & Electric Company 2001-2002 DWR Power Charge Revenue Requirements True-Up Reply Testimony, Pacific Gas & Electric Company Chapter 2 True-Up Calculation, Revised Table 2-1 PG&E's Recommended Pro Rata True up Calculation with SCE's Wholesale Adjustment, Revised Table 2-2, Compliance Case True-up Calculation with SCE's Wholesale Adjustment, Pacific Gas & Electric Company Chapter 3 WAPA True-Up Amount, Appendix A, Statement of Qualifications,
DWR04psRR	30	Rebuttal Testimony of Robert W. Hansen, and Rebuttal Testimony of Michael G. Strong, A.00-11-038, including Table 1 SDG&E Alternate Case True-up Calculation, Dated October 22, 2003

Volume	Record Number	Record Title
DWR04psRR	31	State of California Department of Water Resources Response to Requests for Reconsideration of July 1, 2003 Supplemental Determination of Revenue Requirements, California Code of Regulation Title 23, Section 516 (b), Dated December 4, 2003
DWR04psRR	32	State of California Department of Water Resources Response to Requests for Reconsideration of September 18, 2003 Supplemental Determination of Revenue Requirements, California Code of Regulation Title 23, Section 516 (b), Dated December 4, 2003
DWR04psRR	33	Reply Comments of the California Energy Resources Scheduling Division of the California Department of Water Resources, Before the Federal Energy Regulatory Commission, Dated November 19, 2003
DWR04psRR	34	Request for Clarification or, Alternatively, Rehearing of the California Energy Resources Scheduling Division of the California Department of Water Resources, Before the Federal Energy Regulatory Commission, Dated November 26, 2003
DWR04psRR	35	CPUC Decision 04-01-028, Order Implementing an Interim Allocation of the 2004 Revenue Requirement Determination of the California Department of Water Resources and Truing Up The 2001-2002 Revenue Requirement Determination of the California Department of Water Resources, Dated January 8, 2004 This decision is applicable to this Supplemental Determination, pending a final decision regarding revenue requirement allocation by the CPUC. Adopts Energy Division allocation in Exhibit 04-6A with two adjustments. DA-CRS Revenues to be updated by Utilities' Advice Letters, after agreement with DWR. Each Utility will also adjust its 2004 allocated revenue requirement and remittance rate to reflect the results of the True-up. PG&E authorized to set up a Power Charge Balancing Account. Adopted DWR proposed bond charge rate of $0.00493. Future FERC ordered refunds for 2001-2002 will be allocated on a zonal basis. The Order also adopts the four adjustments proposed by SCE relating to net short calculations and remittances.
DWR04psRR	36	CONFIDENTIAL - PROSYM Output Run 44, Sensitivity Case 1 and 2 - Proprietary Model and Confidential Data contained - Protected under relevant Non Disclosure Agreements - NOT FOR PUBLIC RELEASE
DWR04psRR	37	CONFIDENTIAL - Consultant's Financial Model version CFMG3V32 – Proprietary Model and Confidential Data contained - Protected under relevant Non Disclosure Agreements - NOT FOR PUBLIC RELEASE.
DWR04psRR	38	DWR Electric Power Fund Financial Statements, December 31, 2003 Posted 2/13/04 to the CERS Website.

Volume	Record Number	Record Title
DWR04psRR	39	DWR Electric Power Fund Financial Statements, September 30, 2003 Posted 11/21/03 on the CERS website.
DWR04psRR	40	State of California Department of Water Resources “Reference Item 04-C" in Application 00-11-038 et al before the California Public Utilities Commission 2004 Determination of Revenue Requirement (Permanent Allocation Phase), Dated February 4, 2004 In hearings, ALJ Allen asked the Department to update the cash balance in the operating account. This responds by stating the cash balance in the operating account is approximately $278 million higher at the end of January 2004, than in the September 2003 submittal of Table A-1. The new estimate is based on additional actual data which was unavailable in September 2003. Consequently, the additional data was not included in the record of DWR’s administrative proceeding supporting the 2004 Determination of Revenue Requirements, thus was not examined in a public process.
DWR04psRR	41	CONFIDENTIAL - Customer Load Forecast Data for Pacific Gas & Electric Company, Dated April 2003 – NOT FOR PUBLIC RELEASE
DWR04psRR	42	CONFIDENTIAL – SCE Long-Term Resource Plan Load Forecast Workpapers April 15, 2003 – NOT FOR PUBLIC RELEASE
DWR04psRR	43	CONFIDENTIAL - Customer Load Forecast Data for San Diego Gas & Electric Company, Dated May 2003 – NOT FOR PUBLIC RELEASE
DWR04psRR	44	California Energy Commission Website publication: “California’s 2003 Electricity Supply and Demand Balance and Five-Year Outlook,” Dated May 2003 CEC Report includes California Statewide table of the 2003 peak summer months, California Independent System Operator area table of the 2003 peak summer months, California Statewide graph of the 2003 peak summer months with normal weather, California Statewide graph of the 2003 peak summer months with hot weather, 2003-2008 Annual Summer Peak table with projected operating reserves, and 2003-2008 Annual Summer Peak graph.
DWR04psRR	45	Pacific Gas and Electric Company Advice Letter 2464-E, submitting PG&E’s modified 2004 short-term plan conforming to Decision 03-12-062 Interim Opinion issued on December 18, 2003, Dated January 20, 2004 (redacted version)
DWR04psRR	46	Southern California Edison’s 2003 Energy Resource Recovery Account Application filed with the California Public Utilities Commission on October 3, 2003 (redacted version)

Volume	Record Number	Record Title
DWR04psRR	47	Southern California Edison's Motion for a Authority to File and Maintain Confidential, Commercially Sensitive, Propriety Information Under Seal in relation to its 2003 Energy Resource Recovery Account Application, Dated October 3, 2003 This motion requests that the ALJ maintain Southern California Edison's confidential documents (SCE-1, SCE-2, and SCE-3) under seal.
DWR04psRR	48	Southern California Edison's Motion for a Protective Order in relation to its 2003 Energy Resource Recovery Account Application, Dated October 3, 2003 This motion requests that the ALJ issue an order to set forth conditions upon which parties may obtain access to particular data (SCE-1, SCE-2, and SCE-3) used by Southern California Edison in support of its testimony filed in this application.
DWR04psRR	49	San Diego Gas & Electric Company's Advice Letter 1557-E, Revisions to Certain Portions of SDG&E's Short-Term Procurement Plan in Compliance with D.03-12-062, Dated January 20, 2004 (redacted version)
DWR04psRR	50	CPUC Decision 04-02-024, Opinion Regarding Petition to Modify Decision 03-04-057, Dated February 19, 2004 This Decision permits Direct Access (DA) customers to relocate load to a new location as long as there is no net increase in the DA customer's load within a utility service territory, eliminating the requirement for "one-for-one" or "account-by-account" basis. Also, relieves Energy Service Providers of the requirement to sign an affidavit attesting to the compliance of DA customers with DA load suspension rules.
DWR04psRR	51	CPUC Decision 02-03-055, Opinion Rejecting an Earlier Date than September 20, 2001, for the Suspension of Direct Access, and Implementing the Suspension, as Adopted in D.01-09-060, as Modified by D.01-10-036, Dated March 21, 2002 This decision follows up on the issue of the effective date of the suspension of direct access, which had been pending from previous decisions and rulemakings, keeping the suspension date of September 20, 2001. This order, which applies to the IOUs, prohibits any new arrangements or contracts for direct access service and imposes conditions on unsuspended direct access contracts.
DWR04psRR	52	CPUC Decision 03-05-034, Opinion Adopting Rules for Switching Exemption, Dated May 8, 2003

Volume	Record Number	Record Title
DWR04psRR	53	CPUC Decision 03-07-030, Opinion, Dated July 10, 2003 This decision determines the appropriate level of Direct Access cost responsibility surcharge cap effective for the period subsequent to July 1, 2003.
DWR04psRR	54	Master Settlement Agreement between CDWR and El Paso Energy, including Appendix 1.69 (FERC Settlement Agreement), Appendix 1.89 (Security Document Provisions), Appendix 3.3 (Class Opt Out Formula), Appendix 3.4 (pro forma Federal Court Stipulated Judgment), Appendix 7.5(c) (El Paso Subsidiaries and Affiliates), Appendix 7.6 (Edison Subsidiaries and Affiliates), and Appendix 7.7 (PG&E and PG&E Corporation Subsidiaries and Affiliates), Executed June 24, 2003
DWR04psRR	55	El Paso Settlement Allocation Agreement, Executed June 25, 2003 This allocation agreement entered into by Settling Parties determines how funds will be distributed among the various parties upon settlement closing.
DWR04psRR	56	CPUC Decision 03-10-087, Opinion Regarding Treatment of Consideration Received Pursuant to El Paso Settlement, Dated October 30, 2003 In settlement of various litigation, El Paso has agreed to provide an estimated $1.5 billion (nominal value), composed of 1) $900 million in cash at $45 million per year for 20 years (15 years if El Paso achieves an investment grade credit rating) with a prepayment option for El Paso; 2) $125 million reduction in El Paso's long-term contracts with CDWR; 3) $352 million in up front cash; 4). Proceeds from the sale of more than 26 million shares of El Paso stock (estimated value $227 at the time of the MSA). About $425 million will be payable to CDWR, which CDWR has committed to use to reduce amounts which contribute to the revenue requirement paid by ratepayers under CPUC jurisdiction. About $600 million will be allocated to electric and gas utilities under CPUC jurisdiction. Additional amounts are allocated to out-of-state, muni and non-core gas customers. Decision notes issues are before FERC, San Diego Superior Court and U.S. District Court. This decision also addresses issues of allocation to DA customers.
DWR04psRR	57	CPUC Order Instituting Rulemaking R.03-07-008 Adopting Rules to Account for the Consideration Received by Regulated California Electric and Natural Gas Utilities Under a Settlement with El Paso Natural Gas Company, et al, Dated July 10, 2003
DWR04psRR	58	Department of Water Resources Letter to Calpine Energy Services, L.P. (contract capacity and COD acceptance), Dated April 25, 2003

Volume	Record Number	Record Title
DWR04psRR	59	Letter Amendment between Department of Water Resources and Calpine Energy Services, L.P. (amended capacity payment schedule), Dated July 21, 2003
DWR04psRR	60	Department of Water Resources Letter to GWF Energy, LLC (contract capacity acceptance), Dated August 8, 2003
DWR04psRR	61	Department of Water Resources Letter to CalPeak Power, LLC (conditional capacity test acceptance), Dated September 19, 2003
DWR04psRR	62	Department of Water Resources Letter to Sunrise Power Company, LLC (contract capacity and heat rate acceptance), Dated September 8, 2003
DWR04psRR	63	Record of Coordination – J. Van Horne with C. Hurlock (CERS) regarding Assumptions for 2004 for Demand Reserves Contract, Dated March 3, 2004
DWR04psRR	64	Record of Coordination – J. Van Horne with T. McGivney (CERS) and Follow-up confirming call with Joe Judge (EPG) regarding Assumptions for 2004 for Demand Reserves Contract, Dated March 3, 2004
DWR04psRR	65	Amended and Restated Demand Reserves Purchase Agreement between CDWR and the California Consumer Power Conservation and Financing Authority, Dated April 29, 2003
DWR04psRR	66	DWR 2004 Gas Price Forecast, Revenue Requirements Internal Meeting, Dated February 17, 2004
DWR04psRR	67	DWR Natural Gas Forecast Update 2004 – Overview
DWR04psRR	68	CONFIDENTIAL - Table: Forecast Comparison January 2003, March 2003 Update – NOT FOR PUBLIC RELEASE
DWR04psRR	69	CONFIDENTIAL - Spreadsheet: 2004 Model Base Case HH - NOT FOR PUBLIC RELEASE
DWR04psRR	70	CONFIDENTIAL - Spreadsheet: 2004 Gas Price Model – PS 2-12-04 – NOT FOR PUBLIC RELEASE
DWR04psRR	71	CONFIDENTIAL - Spreadsheet: DWR 2004 Base Case Forecast – Comparisons 021204r – NOT FOR PUBLIC RELEASE
DWR04psRR	72	CONFIDENTIAL - NCI Draft Only Confidential - DWR NG Physical and Financial Hedge Update Meeting – 2004/2005 Revenue Requirements, Dated February 2, 2004 - NOT FOR PUBLIC RELEASE

Volume	Record Number	Record Title
DWR04psRR	73	CONFIDENTIAL – DWR 2004 Gas Price Forecast Final, Dated March 3, 2004 – NOT FOR PUBLIC RELEASE
DWR04psRR	74	CONFIDENTIAL – Considerations for DWR, CPUC OIR R.04-01-025, Reliable Long-Term Gas Supply for California – NOT FOR PUBLIC RELEASE
DWR04psRR	75	National Energy Information Center, Annual Energy Outlook 2004 with Projections to 2025
DWR04psRR	76	Energy Information Administration (DOE) Short-Term Energy Outlook, January 2004
DWR04psRR	77	Minutes of the Diablo Canyon Independent Safety Committee October 2003 Public Meeting, Dated February 23, 2004
DWR04psRR	78	Record of Coordination – Paul Luther with William Eccles, (NEI) regarding PG&E Outage Information (Capacity Factor check) W. Eccles follow up to P. Luther with an e-mail transmittal including the spreadsheet data, Dated February 25, 2004
DWR04psRR	79	California Hydroelectric Energy Snapshot, Electricity Analysis Office, California Energy Commission, Dated February 20, 2004
DWR04psRR	80	Record of Coordination – Nick Nichols with Jim Woodward (CEC) regarding CEC in-State hydro outlook, Dated February 17, 2004.
DWR04psRR	81	Department of Water Resources Memorandum to the California Public Utilities Commission regarding Investor-Owned Utility Advice Letters – Power Charge Remittance Rates and Implementation of Decision 03-09-018, October 2, 2003
DWR04psRR	82	CPUC Decision 03-09-061, Order Granting Petition to Modify, Dated September 18, 2003 This order grants San Diego Gas & Electric Company’s petition to modify D.03-07-030 relating to the implementation of the core/non-core split. It allows SDG&E, like PG&E, to deviate from the 20kW allocation separation criterion.
DWR04psRR	83	Peter Garris letter to ALJ Halligan on the subject of "Application 02-11-017 - PG&E General Rate Case Motion for Approval of Settlement Agreement," Dated October 1, 2003 DWR requests the CPUC reject PG&E recovery of alleged implementation costs associated with the 20/20 program.

Volume	Record Number	Record Title
DWR04psRR	84	CPUC Decision 03-10-016, Opinion, Dated October 2, 2003 This decision orders that the Williams Gas Contract shall be allocated to the gas supply portfolios of SCE and SDG&E, consistent with the DWR determination in September 15, 2003 memorandum. The Kern River scheduling rights shall be allocated to the utilities so that each utility is allowed to schedule 50% of its allocated Williams Gas Contract on Kern River. The utilities shall incorporate the Williams Gas Contracts volumes allocated to them according to this decision into future Gas Supply Plans beginning in October 2003 through March 2004.
DWR04psRR	85	CPUC Decision 03-10-022, Order Denying Rehearing of Decision 03-02-072, Dated October 2, 2003. This decision confirmed the allocation of four biomass contracts; three to PG&E and one to SCE.
DWR04psRR	86	CPUC Decision 03-10-023, Order Denying Rehearing of Decision 03-09-017, Dated October 2, 2003 This decision directs PG&E to pay WAPA amounts with interest, the interest to be a shareholder expense. PG&E asked for rehearing of the interest portion only.
DWR04psRR	87	CPUC Decision 03-10-040, Opinion On Municipal Fee Remittance Methodology Relating to Electricity Sales By California Department of Water Resources, Dated October 16, 2003 PG&E shall implement corrections to calculate and remit municipal surcharge fees to each municipality on a basis consistent with the other IOUs.
DWR04psRR	88	ALJ Ruling Granting Motion to Bifurcate, Dated October 17, 2003 ALJ Allen granted SDG&E petition to bifurcate the 2004 revenue requirement allocation proceeding. An interim allocation of 2004 will be made based on the 2003 methodology. A subsequent proceeding will determine a final allocation process. This ruling sets a tentative schedule for the process.
DWR04psRR	89	Viju Patel letter to Paul Clanon on Draft Resolution E-3852, Dated November 14, 2003 Supports draft resolution to deny PG&E Advice Letter 2354-E but recommends two modifications.
DWR04psRR	90	Viju Patel letter to Paul Clanon regarding Draft Resolution E-3852, Dated November 19, 2003

Volume	Record Number	Record Title
DWR04psRR	91	CPUC Decision 03-12-015, Opinion Regarding Assembly Bill 117's Expanded Registration of Electric Service Providers and Reentry Fee, Dated December 4, 2003 Unless specifically excluded, all entities that offer electric service to customers within the service territory of an electrical corporation in Ca. shall be required to register with the Commission within 120 days, if not already registered.
DWR04psRR	92	Peter Garris letter to ALJ Wong regarding the "Draft Decision on Calculation of Interest Associated with Under-remittances from PG&E," Dated January 5, 2004 The letter discusses WAPA interest issues raised by SCE and SDG&E, the Department considers a rate allocation issue and does not express an opinion on which calculation should be used.
DWR04psRR	94	Andrew Ulmer transmittal to ALJ Allen providing a copy of the August 8, 2002 Ron Nichols Declaration, Dated January 21, 2004 This was requested by various parties in hearings in the 2004 Permanent Allocation Phase. Also attached is supporting documentation pertaining to the delivery of a CD with the requested information provided to the IOUs.
DWR04psRR	95	CPUC Decision 04-01-049, Opinion Regarding Western Area Power Administration Interest, Dated January 22, 2004 Commission Ordered PG&E to pay "WAPA" related interest in the amount of $38 million, to DWR within 20 days from today's date.
DWR04psRR	96	CPUC Decision 04-01-050, Interim Opinion on Rulemaking 01-10-024, Dated January 26, 2004 This decision establishes long-term IOU procurement policy. Among the matters addressed by Decision 04-01-050 are (1) the adoption of a resource adequacy workshop process to implement reserve targets by early 2008; (2) a further moratorium on affiliate transactions with limited exceptions and a requirement that SDG&E demonstrate that its gas procurement activities are comprised solely of SDG&E management as well as a management audit of both SDG&E and PG&E's gas procurement transactions on behalf of DWR. Decision 04-01-050 requires the IOUs to resubmit their long term procurement plans in a new procurement rulemaking to be instituted in Q2 of 2004. The Decision maintains the IOUs semi-annual ERRA filings for 2004 and 2005, which concern the reasonableness of DWR contract administration activities.

Volume	Record Number	Record Title
DWR04psRR	97	Viju Patel letter to Paul Clanon regarding PG&E Advice Letter 2465E, Dated February 4, 2004 PG&E proposed to make certain reductions to DWR's 2004 Revenue Requirements. This letter requests the Commission require PG&E to modify the Advice Letter.
DWR04psRR	98	CPUC Decision 04-02-028, Order Modifying Decision D.04-01-028 and Denying Rehearing of the Decision, as Modified, Dated February 11, 2004 SCE filed for rehearing of D.04-01-028 which allocated the 2004 Revenue Requirements on an interim basis and trued up the 2001-2002 period. The Commission, in this order denied SCE request for rehearing. This Decision modified the Finding of Fact #7 and the Conclusion of Law #7, in wording only. The intent and result was not changed.
DWR04psRR	99	Peter Garris letter to ALJ Allen regarding the "Permanent Allocation of DWR Revenue Requirements," Dated February 18, 2004 This letter was submitted with the scheduled date for comments on the proceeding. DWR states it is willing to maintain utility-specific balancing accounts; argues the CPUC should reject proposed changes to SDG&E and PG&E's remittance methodologies; states the Department does not oppose the elimination of sharing revenues from surplus sales; and argues the CPUC should not modify DWR's 2004 Revenue Requirement to reflect interest payments for under-remittances associated with energy delivered to the WAPA.
DWR04psRR	100	Peter Garris letter to ALJ Janet Econome regarding "Draft Decision Addressing Pacific Gas and Electric Company Rate Design Settlement and Advice Letter 2465E," Dated February 19, 2004 The Department concurs with the draft Decision except for wording relating to the PG&E Power Charge Balance Account ("PCBA"). The Department provides alternative wording to clarify ownership of funds collected from bundled customers.
DWR04psRR	101	Peter Garris letter to the Commission regarding "Application 04-06-040 - Implementation of Comprehensive Settlement Agreement, Dated February 23, 2004 The Department expresses concerns over the CSA relation to Southern California Gas Company. SCE has pointed out the implementation of the proposed structure could impact the Department by $40 million to $58 million during the April 2004 - August 2006 timeframe.

Volume	Record Number	Record Title
DWR04psRR	102	CPUC Decision 04-02-062, Opinion Approving a Rate Design Settlement Lowering Pacific Gas and Electric Company's Rates by $799 Million, Dated February 26, 2004 This decision approves the Settlement Agreement with Respect to Allocation and Rate Design Issues Associated with the Decrease in 2004 Revenue Requirement Arising from Approval of the Modified Settlement Agreement in Commission Decision 03-12-035, filed on January 20, 2004; and orders Pacific Gas and Electric Company to amend Advice Letter 2465-E to conform with the requirements of this decision, effective March 1, 2004, subject to the Commission's Energy Division determination of compliance. PG&E may also revise Advice Letter 2510-G/2460-E, subject to the Energy Division's review, to support the ratemaking mechanisms necessitated by this decision.
DWR04psRR	103	CPUC Decision 04-02-065, Order Denying Rehearing of Decision 04-01-049, Dated February 26, 2004 The Decision denies PG&E's Application for Rehearing of Decision 04-01-049 which required PG&E to pay $38 million to DWR for interest on under-remittances associated with power delivered to WAPA. Decision 04-02-065 rejects PG&E's argument that requiring shareholders to pay the actual costs caused by PG&E's delay in remittances constitutes a civil penalty and that any such penalty should be paid by PG&E ratepayers.
DWR04psRR	104	2004 Supplemental Revenue Requirement Discussion Between DWR and CPUC Energy Division Dated Feb 27, 2003 (sic.) (Note: The presentation contains a typo regarding the document date of 2003, when the document was actually produced in 2004)
DWR04psRR	105	CDWR Rate True-Up Assuming Approval of Advice 2417-E and 2466-E by Mid-March 2004
DWR04psRR	106	PG&E Advice Letter 2417-E, Revision to the Power Charge Remittance Rate Filed in Advice 2328-E-C, Dated September 12, 2003
DWR04psRR	107	PG&E Advice Letter 2419-E, Establish Customer Credit Holding Account and Revise DWR Remittance Rate in Compliance with Decision 03-09-018, Dated September 12, 2003
DWR04psRR	108	U.S. Bankruptcy Court, Northern District of California San Francisco Division, Case No. 01-30923, Stipulation Resolving Claim of Department of Water Resources (Claim No. 12323 as Amended by Claim No. 12592), Order Thereon, Dated February 26, 2004

Volume	Record Number	Record Title
DWR04sRR	109	CONFIDENTIAL - Record of Coordination – Ron Oechsler with Ted Mureau of Southern California Edison Company Regarding SCE 2004 Sales Forecast, Dated March 10, 2004 – NOT FOR PUBLIC RELEASE
DWR04sRR	110	CONFIDENTIAL - Record of Coordination – Ron Oechsler with Greg Katsapis of San Diego Gas and Electric regarding SDG&E Economic Assumptions, Dated March 10, 2004 SDG&E Sales Forecast Data, Dated April 13, 2004 – NOT FOR PUBLIC RELEASE
DWR04sRR	111	CONFIDENTIAL - Southern California Edison's Response to the California Department of Water Resources' Second Data Request Regarding Nuclear Operations, Dated March 8, 2004 (Transmitted on March 16, 2004) – NOT FOR PUBLIC RELEASE
DWR04psRR	112	CONFIDENTIAL - PROSYM Output Run 45, Sensitivity Case 1 and 2 - Proprietary Model and Confidential Data contained - Protected under relevant Non Disclosure Agreements - NOT FOR PUBLIC RELEASE
DWR04sRR	113	CONFIDENTIAL - Consultant's Financial Model version CFMG3V34 – Proprietary Model and Confidential Data contained - Protected under relevant Non Disclosure Agreements - NOT FOR PUBLIC RELEASE.
DWR04sRR	114	CONFIDENTIAL – Stipulation Resolving Claim of Department of Water Resources (Claim No. 12323 as amended by Claim No. 12592); Order Thereon, United States Bankruptcy Court Northern Disctrict of California San Francisco Division, In re Pacific Gas and Electric Company, Case No. 01-30923 DM, February 26, 2004 - NOT FOR PUBLIC RELEASE
DWR04sRR	115	Department of Water Resources Report of Gas Hedging Account Balance as of March 31, 2004
DWR04psRR	116	CPUC Decision 04-01-026, Opinion Regarding End of Rate Control Period and valuation of Generation-Related Assets, Dated January 8, 2004 The Commission found on rehearing that "the rate controls pursuant to AB 1890 ended on January 18, 2001" and that it is unnecessary to perform valuation of utility retained generation assets in identifying this date. This was the effective date of AB6X and provides that regulation of generation assets remains under the CPUC.
DWR04sRR	117	CONFIDENTIAL –Pacific Gas and Electric Company Gas Supply Plan 3 for Tolling Agreements, April 1, 2004 through September 30, 2004, Dated February 2, 2004 - NOT FOR PUBLIC RELEASE

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DWR04sRR	118	CONFIDENTIAL – Southern California Edison Gas Supply Plan for the State of California Department of Water Resources Tolling Agreements, befor the Public Utilities Commission of the State of California (U 338-E) – NOT FOR PUBLIC RELEASE
DWR04sRR	119	CONFIDENTIAL – San Diego Gas and Electric Advice Letter 1561-E (U 902-E) Submittal of SDG&E Gas Supply Plan for DWR Tolling Agreements Pursuant to Decision 03-04-029 and Resolution E-3854, Dated February 2, 2004 - NOT FOR PUBLIC RELEASE
DWR04sRR	120	Federal Energy Regulatory Commission Order Approving Contested Settlement, El Paso Electric Company, Enron Power Marketing, Inc., Enron Capital and Trade Resources Corporation, Docket Nos. EL02-113-000 and EL02-113-002, Dated July 23, 2003
DWR04sRR	121	Offer of Settlement as to Portland General Electric Company, and Agreement and Stipulation, Docket Nos. EL02-114-000 and EL02-115-001, Dated September 26, 2003
DWR04sRR	122	Pacific Gas and Electric Company, Chapter 3, PG&E's Load and Resource Balance from PG&E's 2004 ERRA Update (A.03-08-004), Dated February 17, 2004
DWR04sRR	123	Record of Coordination – Gordon Pickering with Alice Herron of the Pacific Gas and Electric Company Regarding Department of Water Resources' Hedging Program – Margin Account Question, Dated March 24, 2004, 10:00 a.m.
DWR04sRR	124	Record of Coordination – Gordon Pickering with Alice Herron of the Pacific Gas and Electric Company Regarding Department of Water Resources' Hedging Program – Margin Account Modeling, Dated March 24, 2004, 4:00 p.m.
DWR04sRR	125	Record of Coordination – Between Frank Perdue, Mike McCreery and Mike Strong of San Diego Gas and Electric Company Regarding Request for Clarification regarding PROSYM Run 44, Comparison Excel File Attached, Dated March 10, and 30, 2004,
DWR04sRR	126	Record of Coordination – Jeff Van Horne with Tom McGiveney, CERS regarding subsequent CPA Demand Reserve contract capacity levels, Dated March 26, 2004
DWR04sRR	127	California Energy Commission Energy Facility Status, Updated March 19, 2004 The Energy Facility Status is utilized to monitor and track the status of generation in the state and is regularly updated by the CEC on their website http://www.energyca.gov/sitingcases/all_projects.html.

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DWR04sRR	128	Department of Water Resources memorandum from Pete Garris to Paul Clanon, California Public Utilities Commission regarding Investor-Owned Utility Advice Letters—Power Charge Remittance Rates and Implementation of Decision 03-09-018, Attachments Included, Dated March 24, 2004
DWR04sRR	129	Pacific Gas and Electric Company's First Data Request relating to the 2004 Proposed Supplemental Revenue Requirement (entitled PGE's Third Data Request pertaining to 2004), Dated March 12, 2004
DWR04sRR	130	Pacific Gas and Electric Company's Second Data Request relating to the 2004 Proposed Supplemental Revenue Requirement (entitled PGE's Fourth Data Request pertaining to 2004), Dated March 18, 2004
DWR04sRR	131	State of California Department of Water Resources Response Data Requests from Pacific Gas and Electric Company, Dated March 22, 2004 This is the Departments response to PG&Es first Data Request Relating to the 2004 Proposed Supplemental Revenue Requirement (entitled PGE's Third Data Request)
DWR04sRR	132	State of California Department of Water Resources Response to Data Requests from Pacific Gas and Electric Company, Dated March 25, 2004 This is the Departments response to PG&Es second data request Relating to the 2004 Proposed Supplemental Revenue Requirement (entitled PGE's fourth Data Request)
DWR04sRR	133	Pacific Gas and Electric Company's Comments on the Proposed Supplemental Determination of the 2004 Revenue Requirement, Dated April 1, 2004
DWR04sRR	134	San Diego Gas and Electric Company's Comments on the Proposed Supplemental Determination of the 2004 Revenue Requirement, Dated April 1, 2004
DWR04sRR	135	Department of Water Resources Exhibit 1 2003 Summary of Operations Report April 13, 2004
DWR04sRR	136	In The Supreme Court Of The State Of California; Pacific Gas and Electric Company – Petitioner vs. Public Utilities Commission of the State of California – Respondent: CPUC Decision numbers 04-01-049 and 04-02-065; Petition For Writ Of Review: Memorandum of Points and Authorities, and Supporting Exhibits (Volume 1 of 3), dated April 1, 2004.